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Michigan Senate Energy and Technology Committee Meeting Testimony

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I am Lawrence J. Makovich, IHS Vice President and Chief Power Strategist. I am also currently a Senior Fellow at the Mossavar-Rahmani Center for Business and Government in the John F. Kennedy School of Government at Harvard University. I have been involved in electric power industry research for over thirty years while working at National Economic Research Associates, DRI, Cambridge Energy Research Associates and IHS. My research focuses on electricity markets, regulation, economics, and strategy. I have testified numerous times before the US Congress on electric power policy. I have advised the government of China on electric power industry restructuring and testified before the Brazilian Congress on power liberalization. I have examined the impact of deregulation on residential power prices and the development of resource adequacy mechanisms in the CERA Multiclient Studies *Beyond the Crossroads: The Future Direction of Energy Industry Restructuring,* and *Bridging the Missing Money Gap: Assessing Alternative Approaches.* Among other significant research efforts are examinations of the California power crisis in *Crisis by Design: California's Electric Power Crunch* and *Beyond California's Power Crisis: Impact, Solutions, and Lessons.* I have been a lecturer on managerial economics at Northeastern University's Graduate School of Business. I hold a BA from Boston College, an MA from the University of Chicago, and a PhD from the University of Massachusetts.

I testified before the Michigan House Energy Committee on March 18, 2015 regarding the problematic misalignments in the current hybrid electric industry structure. I recently completed a study for DTE Energy entitled "Meeting the Michigan Power Sector Challenge" that focused on these problems and some potential available solutions.

I understand that Committee Chairman Nofs introduced Senate Bill 437 to change the rules governing the provision of electric services to customers from alternative electric suppliers. I want to share my thoughts today on why these changes are a good idea.

The current hybrid Michigan power industry organization

Partial retail open access was never the intended end state for deregulation. It exists because Michigan's deregulation stalled half way along the move from regulation to deregulation. That happened because power deregulation did not work as expected.

Michigan currently faces a power sector challenge because the current partial retail open access increases the probability for electric reliability problems and also produces an unfair distribution of power supply costs among consumers.

The probability is increasing for a power supply shortfall in Michigan's Lower Peninsula within the next few years. The current pipeline of power supply in Michigan does not look big enough to keep up with demand growth and power plant retirements. The most recent regional electric reliability assessment projects a 1,200 to 1,300 megawatt power supply shortfall to meet the expected MISO Zone 7 peak load of over 21,000 Mw in 2016.[1] The assessment indicates regional surpluses and transmission transfer capabilities can address zonal deficits through 2019. The problem is that MISO Zone 7 capacity prices are not signaling the need to invest when a capacity shortfall is expected within less time than the time required to site, permit and build new power supply. The MISO assessment concludes that additional actions are needed to ensure sufficient resources beyond 2019.

The current hybrid electric industry structure in Michigan does not distribute the costs of the power system fairly. All Michigan power consumers—retail open access or utility ratepayers alike—get their electricity from the same source of supply—an integrated regional power system. Yet, retail open access customers pay a smaller share of the costs compared to utility ratepayers. Current misalignments in the Michigan hybrid power sector shift several hundred million dollars per year of costs away from a minority of Michigan retail open access consumers (accounting for little over 10 percent of the state's power consumption) to the majority of customers who remain utility ratepayers. This advantage has not gone unnoticed. As of January 2015, 5,227 customers of DTE and 5,754 customers of CMS are in the queue to acquire these advantages through the existing retail open access program.

To understand why changes to the current hybrid are needed, it is important to know why Michigan deregulation stalled and produced the current hybrid power industry structure with these challenges.

Michigan stalled halfway between regulation and deregulation

Twenty years ago, the idea gained traction that a deregulated power industry relying more on market forces, would perform better than the traditional industry structure relying heavily on regulatory processes. "Competitive, deregulated, liberalized or restructured" electricity industry constructs have been tried with a variety of different models and have proven to be problematic.

[1] 2015 OMS MISO Survey Results, July 2015

The original plan for deregulation was to give all retail consumers the ability to shop around and choose their power supplier—retail open access—including a new set of alternative electric suppliers (AES) that would aggregate customer power needs and buy power from the marketplace on their behalf. On the supply side, the plan was to unbundle utilities—separating the generation business from the transmission and distribution businesses. The goal was to increase competitive forces by instituting bidding for power supply among rival generators with a regulated power grid operated by an independent system operator providing the coordination to enable market interactions between buyers and sellers.

Most restructuring plans reflected a simple faith that the marketplace would work like the economics text book example and produce the desired results—

Reliability—the energy market would produce market-clearing prices that would balance demand and supply in the long run.

Efficiency—an energy market would clear on the basis of short run marginal costs and produce an efficient utilization of available supply options.

Diversity—the level and variability of energy market cash flows would pay for a cost effective mix of demand side resources, peaking, cycling and base load plants of varying fuel and technology types.

Environmental compliance—coordinated environmental policy would internalize environmental costs into the marketplace.

Power industry restructuring did not play out as planned.

California was on the leading edge in the US to implement this type of plan when it passed legislation to deregulate power in 1996, four years ahead of Michigan passing its Public Acts (PA) 141 and 142 to deregulate its power sector.

California ISO and power exchange began operating an energy only market design in 1998.The Michigan and MISO plan was similar to the California plan. Michigan's regional power system MISO began operating an energy only market deregulation plan in 2005.

When California began operating its energy marketplace in 1998, the power system had a surplus of generating capacity. As expected, market produced prices that were too low to provide the necessary cash flows to support new power supply investment. But as time passed, an unexpected result began to emerge. The low wholesale power prices persisted even when demand and supply were in balance with the desired reserve margin. This California electric energy market result was at odds with the economics textbook model of a competitive marketplace. As the California economy expanded and power demand increased further, wholesale energy prices remained below the average total cost of new supply.

California's chronically low prices caused a lack of new power supply entry and thus, underinvestment in power supply. The inevitable consequence was a severe power shortage with dramatic wholesale power price spikes and rolling blackouts. Making matters worse were attempts by some power traders to profit by taking advantage of shortage conditions.

The problem of chronically low market power prices was not unique to California. The root cause was that the technologies employed to cost-effectively generate electricity did not have the characteristics needed to produce a textbook market outcome. This problem is known as the "missing money problem."[2] The problem stems from the characteristics of power generation supply technologies.

Besides this market flaw inherent to power generation technologies, public policies introduced another market distortion through mandates for renewable power and renewable subsidies based on output. These market interventions depress depress market cash flows—on the revenue side, these interventions suppress the level of wholesale prices and on the cost side, these interventions increase costs because cycling power plants have to start up, ramp up and down and shut down more frequently to backup and fill in for the intermittent pattern of renewable power generation.

Some people misinterpret low power prices as the result of the entry of more efficient new competitive suppliers. The evidence does not support this interpretation that deregulation caused new suppliers to win and existing suppliers to lose. The competitive generation business did not produce winning results--the expected growth and profitability did not materialize. The missing money problem caused competitive generating companies to write-down assets, sell power plants at substantial discounts to cost, and in many cases undergo bankruptcy reorganizations. About 5 GW of Michigan's total 30 GW of power supply was originally built by competitive generators. The competitive generating companies owning three quarters of this supply went through bankruptcy since deregulation began; National Energy and Gas Transmission (a unit of PG&E) and Mirant in 2003, and Dynergy in 2011. Financial distress

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[2] The term "missing money" was first used to describe fixed cost recovery in power by Cramton and Stoft in their 2006 paper "The Convergence of Market Designs for Adequate Generating Capacity," written for CAISO's Electricity Oversight Board.

forced the sale of a majority of these power plants at a significant discount to the net cost. As a result, half of the generating capacity built by competitive generating companies in Michigan was sold and is now owned by regulated utilities. In the past decade, competitive generators have not built any conventional generating power plants in Michigan.

The missing money problem is a problem for existing as well as new power plants. In particular, renewable power mandates suppress market clearing energy prices and disproportionately reduce the cash flows of baseload power plants. As a result, critical power supply assets are closing down before it is economic to do so. These premature power plant retirements are not in the best interest of the public because their replacements are more expensive than their continued operation. In addition, depressed market cash flows aggravate the reliability challenge by encouraging uneconomic premature retirement of capacity. For example, Dominion Resources decided to retire the 556 MW Kewaunee nuclear power plant because the market provided cash flow of around 40 $/MWh and going forward costs required cash flows closer to 55 $/MWh. This baseload capacity is being replaced with new supply costing 70 $/MWh.

Kewaunee is not an isolated example. Vermont Yankee is another case where chronically low cash flows triggered a baseload power plant closure that would have been less expensive to keep running than to replace. In Ohio and Illinois, proposed changes are under consideration to provide contractual payments to baseload generators rather than allow market cash flows to trigger premature closures. The counterparties to these contracts are regulated utility ratepayers which will create a de facto move back toward regulated cost recovery in order to ensure reliability.

The inherent technology flaw and unintended consequence of renewable mandates are obscure market problems. As a result, a consensus did not form quickly regarding what had gone wrong or what had to be done to avoid these problems elsewhere. Consequently, industry restructuring lost momentum and most electricity restructuring efforts stalled. Following the California power crisis, seven states passed legislation to suspended power restructuring efforts and others passed legislation to alter deregulation plans.

Michigan's Public Service Commission began altering its deregulation plan by initiating its own study of the evolving power sector. The Public Service Commission Chairman Peter Lark released the "Michigan's 21st Century Electric Energy Plan" in January, 2007. The Michigan Legislature responded to the report's recommendations and altered the course of electricity industry restructuring with the passage of Public Act 286 and 295 in 2008. These new laws made four major changes:

1. **Freeze retail open access**--the plan to eventually have 100 percent of customers with retail open access was changed to limit choice to just customers involved in iron ore mining and processing along with 10% of the remaining average weather normalized retail electric load.
2. **Halt utility unbundling**--The process of requiring utility divestment of generation assets ended.
3. **Establish utility Integrated Resource Planning**-- utilities detailed their expected demand and proposed supply actions, including commission approval of a Certificate of Need for new generating capacity, before commencing construction.
4. **Mandate renewable power supply.** This market intervention overrode the market result and imposed a minimum percentage of power supply from renewable power sources.

The shortcomings of deregulation forced power market institutions to change market rules. The California ISO made structural adjustments after recognizing that the state's efforts to prosecute law-breaking power traders and recover the ill-gotten gains of the power crisis did not address the root cause of the California power shortage. California ISO instituted a resource adequacy rule in 2004 that became binding in 2006. This new rule required all load serving entities to have enough capacity to meet their customers aggregate demand plus a minimum reserve margin. This rule created a demand for capacity that enabled an informal capacity market to arise. An informal marketplace does not organize market interactions but rather relies on capacity buyers and sellers to seek each other out for transactions. The resulting contract prices, terms, and conditions were typically known only to the contract counterparties and thus the informal market provided little capacity price transparency.

MISO followed other power systems in addressing power design market flaws by adding a resource adequacy mandate in 2009. These rules create informal capacity markets but these markets are not very transparent. Four years after mandating a resource adequacy rule, MISO enhanced its resource adequacy mandate by implementing a formal capacity market to clear demand and supply about two months in advance of the annual peak demand.

What MISO is doing now is similar to what PJM was doing in 1997 when it began power restructuring with a power sector design incorporating both energy and capacity markets right from the start. However after five years of experience with its formal capacity market like what MISO has in place now (known as the "capacity credit market"), PJM found that this market design produced a boom and bust capacity price pattern and concluded the power supply investment price signal could be improved by reducing its volatility. PJM responded by evolving its formal capacity market into a formal *forward* capacity market that cleared projected capacity demand and supply three years in advance with a payment commitment term of one to three years. In addition, the volatility of the capacity price was further limited by instituting a managed capacity demand curve and applying more stringent bidding rules to establish the capacity supply curve.

Missing money problem still exists—market based cash flows still fall short of covering the costs of the power system we want.

The current MISO capacity market design is prone to producing boom and bust prices.

Capacity markets are designed to only cover the costs necessary to prevent shortages. Reliability cost benchmark—a peaking unit--the MISO Zone 7 CONE is $90.1 per KW per year and the Net CONE is $65.1 per KW per year.[3] The difference between the MISO CONE and Net Cone shows that even for a peaking power plant with an expected low utilization rate, the contribution from energy market cash flows are important and cover over one-third of annual carrying charges of the upfront investment costs.

The market-clearing MISO Zone 7 capacity price for the summer of 2015 was $1.27 per KW per year. To put this into perspective, the current MISO capacity prices only cover around 2 percent of the Net CONE benchmark cost. This indicates that market prices are currently in the bust phase of a capacity price cycle. A boom and bust pricing pattern is evident in MISO. In the most recent capacity auction, the market clearing price of capacity in MISO zone 4 was almost 10 times higher price than the previous year's auction result.

If the MISO formal capacity market produces the intended result—capacity prices that average to a price that equals the average total cost of new capacity in the long run (net of energy market margins)—then the booms have to be high enough to make up for the busts over the life of the generating capacity. If boom and bust prices each prevail roughly half of the time, then prices would have to be a multiple of the Net CONE in the boom phase to produce an average across all years equal to Net CONE.

Retail open access options shift capacity cost burdens

The combination of boom and bust pricing patterns for MISO Zone 7 capacity plus the wholesale energy price correlated to volatile natural gas prices patterns make the market costs of power (the sum of market capacity and energy prices) significantly more variable through

[3] MISO Locational Resource Zone Cost of New Entry Filing to the Federal Energy Regulatory Commission, September 3, 2013.

time compared to the regulated costs of power. The unintended consequence of halting retail open access at 10 percent of power demand is the provision of a valuable option to some customers but not others. A combination of a boom phase in the capacity market and cyclical highs in natural gas prices can trigger retail open access customers to switch power suppliers in an effort to always the lower of regulated and AES prices at any given point in time. As a result, consumers with an option to switch can avoid paying their share of capacity costs by timing their switching activity between AES and regulated utilities.

Short run switching options hinder balancing demand and supply in the long run

The introduction of the MISO capacity market was intended to address the inherent missing money problem at the root of power market reliability problems. However, the ability for customers to switch suppliers in the short run creates uncertainty regarding who is responsible to plan for their power supply in the long run. The current problem is that capacity prices are not moving into the boom phase and producing an investment price signal far enough in advance of shortage conditions to allow for the lead time for power plant development. Under these conditions, when market-sourcing power suppliers try to pass on the booming capacity prices to retail open access customers, these customers will face a strong economic incentive to switch back to regulated power provider and pay the lower capacity rates that reflect the average embedded historical capacity cost. As the projected power supply shortfall draws closer, the probability grows that utilities will not have sufficient time to reliably meet this increase in regulated customer demand.

The margin for error in balancing power demand and supply is small. In Michigan, a reserve margin between 14 and 15 % is required to reliably balance power demand and supply. Dropping just 5 percent short of the target reserve margin substantially increases the probability of serious power system problems—emergency load shedding, brownouts, and price spikes altogether similar to what happened in California in 2000-2001.

In 2006, the Michigan Public Service Commission (MPSC) looked ahead and projected an electric demand and supply balance in the near future but an insufficient pipeline of new supply under development for subsequent years. Shortly after the MPSC reliability assessment, the business cycle produced an unanticipated temporary reprieve from the impending power supply shortfall in the Lower Peninsula. At the end of 2007, the most severe economic downturn since the Great Depression began. Reduced business activity and lower household purchasing power reduced power demand. The economic downturn dropped Michigan peak power demand by over 3,000 MW (December 2007 to June 2009).

System-wide benefit free riders

Michigan utility ratepayers create overall system benefits funding investments in demand-side management, production efficiency (peaking, cycling and base load), risk management, and mitigation of environmental impacts. Since utility-owned power plants participate in the market, these benefits spill over to the market outcome and produce cleaner, more cost effective and less volatile market clearing power prices.

The problems in deregulated electricity markets are reducing power supply diversity. Investments in production efficiency and production cost risk management produce a big payoff. For example, if Michigan power supply lacked fuel and technology diversity and relied on a single fuel and technology--only natural gas-fired combustion turbines for power supply--then the wholesale price of power in the state of Michigan from 2010 to 2013 would have been over 50% higher, with a monthly price variation would have been over three times greater than the actual level and variations in market-clearing prices.

The costs of environmental controls at utility power plants provide benefits to all customers yet the costs are often borne by just the regulated consumers. This uneven cost burden may increase when Michigan develops within the next several years, its state implementation plan for the EPA final rule in the Clean Power Plan. This unfair cost burden will arise if the costs of utility actions to achieve compliance are borne by ratepayers while the benefits of achieving the statewide CO2 emission goals are shared across all consumers in the state.

In regulated utility rates, non-variable generating costs reflect the average historic embedded cost of capacity in the utility generation portfolio. The component of the regulated price covering the average cost of capacity ranges from 3 to 4 cents per kWh across different customers classes. This translates into a Michigan regulated capacity charge of about $200 per kW per year. Roughly one third of the regulated embedded capacity charge covers the cost of investments to provide reliability and the other two-thirds covers the cost to provide the production efficiencies through a mix of peaking, cycling, base load and demand side resources as well as provide risk management through a diverse fuel and technology supply mix and also provide the environmental impact management from compliance with existing environmental regulations.

Retail open access customers are free riders because the system-wide benefits funded by ratepayers cannot be excluded from customers choosing to be served by market sourced power suppliers.

Conclusion

The current Michigan hybrid power industry structure is not delivering the desired results.

Reliable service-- Short run switching available to retail open access customers creates uncertainty and insufficient lead times to adequately develop long run power supply. In addition, the option provides a way for retail open access customers to avoid paying the full cost of reliability.

Efficient generation--The MISO energy market produces an efficient short run utilization of available generation resources but energy market interventions suppress the energy market cash flows needed to support an efficient mix of peaking, cycling and base load power plants in the long run.

Diverse power supply—market interventions that depress energy market cash flows are not supporting a cost-effective combination of demand side resources, peaking, cycling, base load and renewable resources. Nevertheless, utility ratepayers fund the current diverse portfolio that provide system-wide benefits and thus provide a free ride for retail open access customers.

Environmentally compliant production—Market cash flows do not cover most of the costs of environmental control. Again, utility ratepayers fund investments that provide system-wide environmental benefits and thus provide a free for retail open access customers.

Realigning Michigan regulations and the marketplace.

Two options exist to realign Michigan regulations and the marketplace.

> **Phase out partial retail open access**—the most straightforward realignment option involves phasing out retail open access by mandating a shift back to utility supply in the next few years when demand and supply come into balance and capacity prices are poised to move into a boom phase of the pricing cycle. Moving Michigan away from the hybrid and back to universal regulation can eliminate the free rider problem in power cost recovery which is especially important at a time when the state will need to incur significant costs to comply with the Clean Power Plan.
>
> **Alter partial retail open access**—with two major revisions. First, a surcharge needs to be added to the purchased power charges to eliminate the free rider problem and level the burden of recovering the costs of utility investments that provide system-wide

efficiency, risk management, and environmental benefits. Second, retail open access consumer commitments need to be extended to align with a power plant investment horizon. The goal is to create purchased power agreements with a long enough term to support a stable environment for power plant investment. In addition, the expiration dates of customer supply commitments ought to be staggered to limit potential demand swings in any given year.

The sooner Michigan addresses the problems of the status quo--uneven cost burdens, the unfair switching option and the increasing probability for power supply shortage, the sooner Michigan can insure its power system remains reliable, efficient and environmentally compliant. Corrective actions will enable a fair distribution of costs to customer classes and maintain the competitiveness of electric input costs to Michigan businesses operating in the global economy.

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Meeting the Michigan Power Sector Challenge

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STRATEGIC REPORT

DTE | Special Report

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Meeting the Michigan Power Sector Challenge

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Meeting the Michigan Power Sector Challenge

Executive summary

Michigan faces a power sector challenge because of problematic misalignments in the current hybrid industry structure. This current hybrid of regulation and markets was never the intended end state of deregulation. Rather, the hybrid came about because power deregulation did not unfold as planned.

Michigan power deregulation began 14 years ago. As Michigan began implementing its power restructuring plan, the problematic realities of power industry restructuring efforts elsewhere were coming to light. In particular, the gap between the expectations and the reality of deregulation became increasingly apparent in California, where the restructuring process had begun about seven years ahead of Michigan. A serious shortage developed in California because power markets failed to produce prices high enough to cover the average costs of power generation; and as a result, power supply investments did not keep pace with customer needs.

The tendency of competitive power markets to leave a gap between market-clearing prices and average total costs is known as the "missing money problem."[1] The missing money problem has three major consequences. The first is the risk of underinvestment in new power supply. Second, low prices cause too many existing power plants to be retired early, even though their continued operation would be far less costly than replacing the supply they provide. Third, low prices distort market signals and lead to an inefficient mix of fuels and technologies. IHS Energy estimates that such inefficiencies are moving the cost of fuel used to generate electricity in the United States to a level 9% higher than it should be.

There is no one-size-fits-all solution to the missing money problem. We have studied the particular challenge facing Michigan and recommend the following two options:

- **Phase out partial retail open access.** The most straightforward realignment option involves phasing out retail open access by mandating a shift back to regulated utility supply.
- **Alter partial retail open access—with two major revisions.** First, a surcharge needs to be added to alternative energy supplier (AES) power charges to address the free rider problem and level the burden across all customers for recovering utility investments in systemwide efficiency and risk management. Second, a rule needs to be put in place requiring AESs to demonstrate a firm forward supply arrangement for the projected needs of their current customers to provide enough lead time (at least five to seven years) to develop not only peaking units but also the cycling and base-load power plants necessary for efficient and reliable power supply.

Deregulation: The gap between expectations and reality

The California power crisis exposed the flaws in power market deregulation plans. The cost recovery shortfall that caused underinvestment occurred for two reasons, one inherent in power generation and one imposed by legislative and regulatory interventions. First, power generation technologies have inherent characteristics that prevent an electric energy-only market design from delivering prices high enough to balance demand and supply in the long run. Second, regulations imposed on power supply, including both subsidies and mandated generation shares for renewable power, create the unintended consequence of suppressing energy market prices. Both the inherent and the imposed dimensions of this problem cause a persistent gap between prices and average total costs. This gap prevented deregulated power markets from reaching the stable, economics textbook market result that people had expected.

Markets failing to produce a textbook result owing to an inherent characteristic of the production technology are neither new nor unique to the power business. A nineteenth-century French engineer and economist, Jules Dupuit, analyzed market failure in the railroad industry resulting from the gap between market prices and average total costs.[2] Dupuit

1. The term *missing money* was used to describe fixed-cost recovery in power by Peter Cramton and Steven Stoft in their 2006 paper, "The Convergence of Market Designs for Adequate Generating Capacity," written for the California Independent System Operator's Electricity Oversight Board.

2. Jules Dupuit, "De l'Influence des Péages sur l'Utilité des Voies de Communication," *Annales des Ponts et Chaussées* no. 207, 1849, p. 170–248.

illustrated the root cause of the problem by developing the example of a bridge—a technology with a large up-front capital cost and thus a positive average total cost, but also a technology with a zero marginal cost for providing bridge crossings. The incremental cost is zero because it costs the bridge owner nothing extra to let someone cross the bridge.[3] Dupuit understood that in a marketplace all rival bridge owners would be willing to take any customer payment above zero in order to provide some contribution to their fixed costs. He argued that a market for bridge services would not work because competitive forces would logically drive the market price toward zero. Thus, the market would inherently fail to provide cost recovery and thus fail to attract the investment needed to produce a stable, long-run market result.

Power production technologies have cost characteristics similar to Dupuit's bridges. In particular, wind and solar technologies have significant up-front costs and zero incremental generating costs. More generally, the technologies employed to cost-effectively generate electricity do not have the incremental cost characteristics needed to produce a textbook market outcome in which prices keep demand and supply in long-run balance. Contemporary economists call this the missing money problem. IHS Energy recently completed a study on behalf of a group of industry stakeholders—including power system operators, merchant generators, and traditional utilities—concerning the causes, consequences, and solutions to the missing money problem.[4] The study found that there is no one-size-fits-all solution to the missing money problem and that several approaches can meaningfully address the problem if they align with power system conditions. The IHS Energy study's research and key findings served as the basis for our current more in-depth study of the challenge facing the Michigan power sector. In this case, the Midcontinent Independent System Operator (MISO) regional power market conditions address some, but not all, of the missing money problem. Therefore, the use of regulated cost recovery to bridge the remaining missing money gap is a logical solution. However, the presence of the current retail open access undermines the effectiveness of this industry structure.

Creating the hybrid power industry structure

The economic impact of the California power crisis of 2000 to 2001 was so severe that it altered power industry restructuring plans not only in California but around the world. Following the crisis, California made structural adjustments to its market rules after recognizing that prosecuting law-breaking power traders and trying to recover the ill-gotten gains of the power crisis did not address the root cause of the shortages. Initially, California employed an ad hoc approach of long-term power supply contracts. Eventually, California instituted a resource adequacy rule in 2004 that became binding in 2006. The rule required all load-serving entities to have enough capacity to meet their customers' aggregate demand plus a minimum reserve margin. This rule created a demand for capacity and enabled an informal capacity market to arise. An informal marketplace does not organize market interactions but rather relies on capacity buyers and sellers to seek each other out for transactions.

MISO began deregulation with an energy-only market design similar to California's. After California made its rule changes, MISO also altered its rules to include a resource adequacy mandate in 2009. The resource adequacy mandate created an informal capacity market in MISO. Four years after the resource adequacy rule, MISO enhanced the mandate by implementing a formal capacity market to clear demand and supply about two months in advance of the annual peak demand. With this enhanced approach, MISO runs a voluntary capacity auction each April to balance capacity demand and supply for the 12-month supply period beginning each June (2015 was its third auction). The current MISO capacity market enables AESs to cover any capacity needs that have not been covered in the informal marketplace and yet are still needed to meet their short-term resource adequacy mandate.[5]

MISO's neighboring power system, PJM, began power restructuring in 1997 with a design incorporating both energy and capacity markets. PJM's initial capacity market design (known as the "capacity credit market") was similar to the current MISO capacity market design. However, five years of experience in PJM showed that normal fluctuations of demand and supply conditions from one year to the next produced a boom-and-bust pricing pattern. A similar pattern is emerging in MISO. In the most recent capacity auction, capacity prices in MISO Zone 4 moved up nearly ninefold from the prior year's auction price. PJM concluded that this approach did not fully address the inherent dimension of the missing money problem; it responded by evolving its formal capacity market into a formal *forward* capacity market that cleared projected

3. Jules Dupuit, "De la mesure de l'utilité des travaux publics," *Annales des Ponts et Chaussees*, second series, VIII, 1844.

4. See the IHS Energy Multiclient Study *Missing Money in Competitive Power Generator Cash Flows: Causes, consequences, and solutions*, November 2014.

5. "First Annual Capacity Auction Cleared Under New RA Construct," MISO Energy, 5 April 2013.

capacity demand and supply three years in advance with a payment commitment term of one to three years. In addition, PJM further limited the volatility of the capacity price by instituting a managed capacity demand curve and applying more stringent bidding rules to establish the capacity supply curve.

Experience with competitive power markets not only exposed the inherent missing money problem in energy markets but also indicated that even with a capacity market, very few wind and solar power generating technologies were likely to be built. However, growing concern over global warming led to the establishment of renewable portfolio standards that overrode this market outcome and imposed minimum power supply shares for renewable resources. The unintended consequence of imposing these power supplies into the generation mix was to depress the energy market–clearing price and aggravate the missing money problem. This suppression of market prices from renewable power mandates is the primary cause of the imposed dimension of the missing money problem.

The original plan for deregulation was to increase competitive forces by giving all retail consumers the ability to shop around and choose their power supplier—including a new set of AESs that would aggregate customer power needs and buy power from the marketplace on their behalf. On the supply side, deregulation involved two steps. The first step involved deregulating the generation business while preserving regulation in the transmission and distribution businesses. The second step was to continue to regulate the wires business while increasing competitive forces in power generation. Doing this required establishing a regional electric energy market with an independent system operator (ISO) to coordinate market interactions between buyers and sellers. The expectation was that this power industry structure would produce energy market–clearing prices sufficient to support timely and adequate investment to keep demand and supply in balance over the long run.

Michigan enacted its power deregulation plan into law 14 years ago with the passage of Public Acts (PAs) 141 and 142. From 2001 to 2008, PA 141 allowed retail open access. During this time, retail open access participation ranged from 3% to 20% of utility load.[6] On 1 April 2005, MISO began operating the regional electric energy marketplace.

Michigan's Public Service Commission (PSC) altered its deregulation plan by initiating its own study of the evolving power sector. PSC Chairman Peter Lark released the "Michigan's 21st Century Electric Energy Plan" in January 2007. The Michigan Legislature responded to the report's recommendations and changed the course of electricity industry restructuring with the passage of PAs 286 and 295 in 2008. This legislation made three major changes:

- **Freezing retail open access.** The plan to eventually have 100% of customers with retail open access was changed to limit it to just customers involved in iron ore mining and processing, along with 10% of the remaining average weather-normalized retail electric load. Traditional regulated utilities supply the remaining roughly 90% of power consumption in the state.

- **Establishing utility integrated resource planning.** The plan changed from relying on the marketplace for timely and adequate electric supply expansion in favor of an integrated resource planning process in which utilities detailed their expected demand and proposed supply actions, including PSC approval of a Certificate of Need for new generating capacity before commencing construction.

- **Mandating renewable power supply.** This market intervention overrode the market result and imposed a minimum percentage of power supply from renewable power sources.

The changes Michigan made to its deregulation plan created the current hybrid power industry structure, and the changes to MISO market rules addressed some, but not all, of the missing money problem. These are the defining characteristics of the current Michigan power business landscape and the source of the problematic misalignments. These misalignments cause three power sector challenges in Michigan:

- **Unfair power supply cost burdens (free riders).** The missing money problem exists in the MISO power marketplace. Consequently, market cash flows from energy and capacity markets chronically fall short of covering the total cost of power supply. As a result, retail open access customers choosing suppliers that source capacity and energy from

6. "Readying Michigan to Make Good Energy Decisions: Electric Choice," Michigan Public Service Commission and Michigan Economic Development Corporation, 15 October 2013.

the market typically pay less than full cost. In contrast, utility ratepayers cover total costs. Regulated utility charges fund utility investments in a diverse power supply portfolio that includes cycling and base-load power plants as well as renewables. This diverse generating portfolio produces a range of systemwide benefits because these power supply resources participate in the energy market. The benefits they create—lower off-peak prices, cost risk management, and environmental controls—cannot be excluded from any buyers in the market. Thus, retail open access customers are free riders on the systemwide benefits paid for by utility ratepayers.

- **A discriminatory option (to switch).** Retail open access customers have the option to pay the lower of market or regulated power prices. Although the unresolved missing money problem means market prices for energy and capacity are chronically below average total costs, these market prices are far more volatile than regulated power prices. The MISO capacity market design produces a boom-and-bust pricing pattern, and the energy market reflects incremental cost-based power supply bids that are often linked to natural gas prices—the most volatile of power generation fuel costs. As a result, there is potential for energy and capacity price swings (particularly in a shortage period) to provide a valuable option to some customers to switch temporarily back to regulated power suppliers until the market price swings in reverse. As conditions reverse, customers can switch back again to AESs that source energy and capacity from the marketplace.

- **Increased probability of Lower Peninsula power supply shortages (reliability challenges).** Short-term demand and supply switching options hinder the long-term balancing of demand and supply to ensure reliable power supply. The flexibility of retail open access customers to switch power suppliers in the short run makes it unclear who is responsible for planning for their capacity needs in the future. Further, short-term customer switching makes it difficult for suppliers to add capacity fast enough to meet the demand. Similarly, some power suppliers have the ability to switch power markets in the short run. The most recent example is the Covert power plant—one of the largest merchant power plants in Michigan—that is switching its (approximately) 1,000 megawatt (MW) power supply away from the MISO market and into the PJM market because PJM energy and capacity prices are expected to be higher. This 1,000 MW shift in power supply is under way, even though the most recent regional electric reliability survey indicates the need for more than 1,000 MW of capacity transfers from other MISO zones into MISO Zone 7 (Michigan Lower Peninsula) in 2016. These capacity transfers from other zones are needed to make up for the projected 1,200 to 1,300 MW shortfall in power supply to meet the expected MISO Zone 7 peak load in 2016. To put this shortfall in context, the expected Zone 7 capacity requirement for 2016 is 24.3 GW. The survey indicates that expected load growth will diminish the surplus capacity in MISO zones available to Zone 7 by 2019. Therefore, the survey concludes that additional actions are required in the near term to ensure sufficient power supply resources beyond 2019.[7]

The opportunity to realign regulation and the market

Misalignments in the current Michigan hybrid industry structure create three major problems: (1) an unfair distribution of power supply costs among consumers, (2) a switching option that discriminates in favor of some customers at the expense of other customers, and (3) an increase in the probability of electric reliability problems. The ramifications of these problems are

- **Power costs distribution.** The current Michigan hybrid power sector misalignments shift roughly $300 million per year of costs away from a minority of Michigan consumers (retail open access customers account for a little over 10% of the state's power consumption and approximately 0.5% of customers) to the majority of customers who are utility ratepayers. On average, two-thirds of the cost shift involves the fixed costs of power supply, and the remaining one-third reflects variable electric energy cost shifts. Since the systemwide benefits of utility investments are available to all customers, this allows a free ride to retail open access customers.

- **Switching.** This ongoing free rider problem is magnified by the option to switch suppliers. Although market prices for energy and capacity are currently below regulated prices, reflecting average total costs, sometimes the greater volatility of market prices creates conditions that reverse this relationship. As a result, although retail open access and utility ratepayers are both supplied from the same integrated power supply, retail open access customers have the option to

7. *2015 OMS* [Organization of MISO States] *MISO Survey Results*, July 2015.

always pay the lower of AES or utility power prices. This option is discriminatory because it allows some customers to pay less at the expense of others.

Not surprisingly, customers recognize the value of a free ride and a discriminatory open access retail choice option. The waiting list for the retail open access program is twice as large as the number of customers allowed to participate under current regulations.

- **System reliability.** The probability of unreliable power supply in Michigan's Lower Peninsula is increasing. The misalignment between short-run customer switching and long-run supply planning means that customer demands can shift back to regulated utility suppliers faster than utilities can site, permit, and construct required new capacity. This uncertainty regarding who is responsible for consumer demand in the long run is one reason why the current pipeline of new supply is less than the amount needed to keep up with demand increases and replace retiring generating resources. The margin for error in balancing power demand and supply is small. In Michigan, a reserve margin of 14.8% is required to reliably balance power demand and supply. Dropping just 5 percentage points short of the target reserve margin substantially increases the probability of serious power system problems—emergency load shedding, brownouts, and price spikes altogether similar to what happened in California in 2000–01.

The implication is clear—the time has come for Michigan to realign its electric regulations with market realities. Based on IHS Energy research, Michigan has two options to realign regulations and the marketplace:

- **Phase out partial retail open access.** The most straightforward realignment option involves phasing out retail open access by mandating a shift back to utility supply.
- **Alter partial retail open access—with two major revisions.** This is a less definitive and more complex option. First, a surcharge needs to be added to the retail open access purchased power charges to address the free rider problem and level the burden across all customers of recovering utility investments in systemwide efficiency, risk management, and environmental benefits. Second, a rule needs to be put in place requiring AESs to demonstrate a firm forward supply arrangement for the projected needs of their current customers to provide enough lead time (at least five to seven years) to develop not only peaking units but also the cycling and base-load power plants necessary for efficient and reliable power supply.

Conclusion

All too often, it takes a crisis to force changes in the power industry structure. In the case of the California power crisis, the evidence that underinvestment was preventing power supply from keeping up with demand was apparent, but actions did not materialize until after a severe shortage unfolded. More recently, the problems of coordinating natural gas and power supply infrastructure simmered for years on a back burner until the polar vortex in the 2013/14 winter forced power systems to reevaluate how they defined and paid for firm power supply.

Michigan has misalignments in its current hybrid power industry structure that create problems—uneven and unfair cost burdens, a discriminatory switching option, and the increasing probability for insufficient power system reliability. But rather than wait for these problems to produce a crisis, Michigan can move forward and ensure that its power system remains reliable, efficient, and environmentally compliant. Corrective actions will enable a fair distribution of costs to customer classes and maintain the competitiveness of electric input costs to Michigan businesses.

Michigan's electric power industry structure: An unplanned hybrid

Power industry restructuring did not play out as planned. US power industry restructuring began in the 1990s. At that time, the traditional power industry structure involved the regulation of franchised power companies providing generation, transmission, distribution, and customer billing services. Prior to deregulation, the traditional industry structure produced significant differences in power prices from one utility to the next. The enthusiasm to move away from traditional regulation and rely more on market forces reflected the hope that the introduction of more competitive forces would drive out these cost differences, encourage innovation, and lower power bills. Most restructuring plans reflected a simple faith that the marketplace would produce a textbook result where market-clearing prices for electric energy would signal timely investment and support adequate power supply development.

In Michigan, the traditional regulated industry structure involved two regulated utilities: Consumers Energy (CMS) and Detroit Edison (DTE) supplied the capacity, generation, transmission, distribution, and customer interface for approximately 90% of Michigan electric consumer electricity consumption. The regulated rates charged to consumers reflected the average total costs of power supply allocated to different classes of customers based on cost responsibility.

Pressures to reduce power price differences between utilities were much greater in some places compared to others. As a result, there was no standard path or pace to restructuring the power sector. Some states made minor changes, while other states substantially increased the role of market forces on both the consumer (retail) and producer (wholesale) sides of the power business. Michigan was among the 17 states (California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, and Texas) plus the District of Columbia that expanded their reliance on market forces to some degree on both the wholesale and retail sides of the power business.

Michigan's electric restructuring plan went further than most state plans in setting goals and timetables to move from regulation to deregulation. The original plan for deregulation was to give all retail consumers the ability to shop around and choose their power supplier—including a new set of AESs that would aggregate customer power needs and buy power from the marketplace on their behalf. The goal was to increase competitive forces by unleashing retail customers to shop around for the best deal. On the supply side, the plan was to unbundle utilities—separating the generation business from the transmission and distribution businesses. The idea was to continue to regulate the wires side of the business and increase competitive forces by instituting competitive bidding for power supply among rival generators, with a regulated power grid operated by an ISO providing the coordination to enable market interactions between buyers and sellers. The expectation was that this power industry structure would produce energy market–clearing prices sufficient to support timely and adequate investment to keep demand and supply in balance over the long run.

Michigan enacted its power deregulation plan into law 14 years ago with the passage of PAs 141 and 142. From 2001 to 2008, PA 141 allowed retail open access (2000 PA 141). During this time, retail open access participation ranged from 3% to 20% of utility load.[8] However, as Michigan began implementing its power restructuring plan, the problematic realities of power industry restructuring efforts elsewhere were coming to light. In particular, the gap between deregulation expectations and the reality became increasingly apparent in California, where the restructuring process had begun about seven years ahead of Michigan.

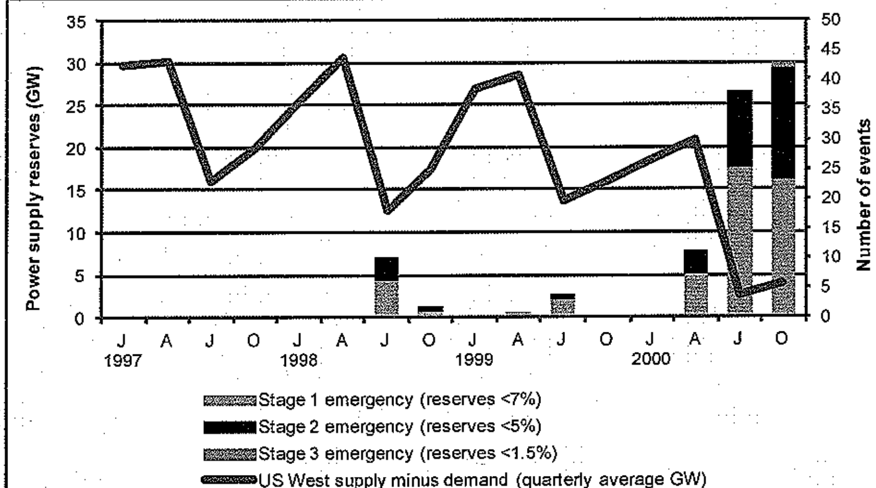
Both the initial California and MISO market designs involved only an electric energy market. When California began operating its energy marketplace in 1998, the power system had a surplus of generating capacity. As expected with surplus supply conditions, market operations produced market-clearing prices for electric energy that were too low to provide the cash flows necessary to support new power supply investment. But as time passed, an unexpected result began to emerge. The low wholesale power prices persisted even when load growth resolved surplus supply and brought demand and supply into balance with the desired reserve margin. This California electric energy market result was at odds with the economics textbook model of a competitive marketplace. As the California economy expanded and power demand increased further, wholesale energy prices remained below the average total cost of new supply.

8. "Readying Michigan to Make Good Energy Decisions: Electric Choice," Michigan Public Service Commission and Michigan Economic Development Corporation, 15 October 2013.

The chronically low prices produced by an energy-only market design in California caused underinvestment in power supply. Consequently, the continued reserve margin decline brought supply below the level needed to maintain reliability and increased the probability of power reliability problems. Figure 1 shows the declining supply reserve and the increasing frequency of shortage-driven stage 1–3 emergency procedures. The inevitable consequence was a severe power shortage with dramatic wholesale power price spikes and rolling blackouts. Making matters worse, some power traders attempted to profit by taking advantage of shortage conditions.

Figure 1

Western demand growth strains system



Note: GW = gigawatt(s).
Source: IHS Energy

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The problem of chronically low market power prices was not unique to California. Most electric energy markets produced market-clearing power prices that were consistently below the average total cost of power supply. These conditions caused "merchant" generators—power suppliers that primarily rely on market cash flows to recover costs—to write down assets, sell power plants at substantial discounts to cost, and in many cases undergo bankruptcy reorganizations. About 5 GW of Michigan's total 30 GW of power supply was originally built by merchant generators. Since deregulation began, the three merchant generating companies owning approximately 75% of this supply have gone through bankruptcy: National Energy and Gas Transmission (a unit of PG&E) and Mirant in 2003, and Dynegy in 2011. Financial distress forced the sale of a majority of these power plants at a significant discount to the net cost. Half of the generating capacity originally built by merchant generating companies in Michigan is now owned by regulated utilities. In the past decade, merchant generators have not built any conventional generating power plants in Michigan.

Despite low wholesale prices for merchant generators, consumer power bills went up rather than down in the era of deregulation owing to the costs imposed by market interventions to avert a California style crisis and to scale up wind and solar power generation. The accumulating evidence drove industry observers to agree that power industry restructuring was not working as planned (see the box "Reassessing power industry restructuring").

A consensus did not quickly form regarding what had gone wrong in the California power deregulation process because the underlying market flaw remained obscure. As a result, it was not clear what needed to be done to move forward and avoid similar problems in other efforts to implement deregulation. Following the California power crisis, seven states—Arizona, Arkansas, California, Nevada, New Mexico, Virginia, and Wyoming—passed legislation to suspend power restructuring efforts. Consequently, industry restructuring lost momentum, and most electricity restructuring efforts stalled.

Inherent and imposed power market flaws produce a missing money problem

The root causes of the failures in implementing power deregulation are a complex mix of inherent market flaws and unintended consequences from regulations imposed on power supply.

A focus on markets that fail to produce textbook market results because an inherent characteristic of the supply technology is neither new nor unique to the power business. A nineteenth-century French engineer and economist, Jules Dupuit, analyzed the investment problem in the railroad industry resulting from the gap between fixed and variable

Reassessing power industry restructuring

"States restructured their electric power industry on the premise that competition would reduce resource costs more effectively than regulation and would result in lower prices for consumers. To date, the competitive market for residential and small commercial customers has not materialized as anticipated."

—Consumer Energy Council of America, April 2003

"Deregulation promised lower costs, more consumer choice, more reliability, and fewer government bailouts. So far, it has produced higher prices, more manipulation of consumers, volatility, brownouts, and bailouts running into the tens of billions."

—*BusinessWeek* Online, October 2002

"Electric utility restructuring was initiated in the 1990s to remedy the problem of relatively high electricity costs in the Northeast and California. While politicians hoped that reform would allow low-cost electricity to flow to high-cost states and that competition would reduce prices, economists wanted reform to eliminate regulatory incentives to overbuild generating capacity and spur the introduction of real-time prices for electricity. Unfortunately, high-cost states have seen little price relief, and competition has had a negligible impact on prices."

—CATO Institute, November 2004

"Deregulation of the electricity market in the U.S. is often held up as a boon for consumers, a way to shake up monopoly utilities and sharply lower rates for residential customers. ...But stirring up competition has turned out be much tougher than states expected, mainly because erratic wholesale electricity prices have pushed up retail rates as well."

—*The Wall Street Journal,* March 2005

costs.[9] Dupuit communicated the root cause of the problem by developing the example of a bridge—a technology with a large up-front capital cost, a positive average total cost but a zero marginal cost for bridge crossings.[10] He argued that competitive forces would logically drive the market price to zero and underinvestment would lead to market failure.

The power business is another exception to the general market rule. The underlying inherent flaw in power deregulation is that the technologies employed to cost-effectively generate electricity do not have the characteristics needed to produce a textbook market outcome in which prices keep demand and supply in long-run balance. Contemporary economists call this the missing money problem.[11]

The missing money problem prevents the normal corrective forces of the textbook marketplace from moving the power market into a long-run demand and supply balance. In an economics textbook, the industry marketplace employs production technologies that generate corrective forces when market conditions are out of long-run balance. In particular, when prices are below average total costs, suppliers will not invest capital in new productive capacity. However, a lack of new investment in productive capacity does not mean supply will cease. Existing demand is met because market-clearing prices can settle below average total costs but above the variable production costs. Under these conditions, suppliers produce output and generate cash flows that provide some contribution to the capital already deployed in manufacturing capacity. Nevertheless, as capital wears out and is not replaced and/or as consumer demand increases, balancing demand and supply requires the market-clearing price to rise enough to cover the higher

9. Jules Dupuit, "De l'Influence des Péages sur l'Utilité des Voies de Communication," *Annales des Ponts et Chaussées,* no. 207, 1849, p. 170–248.

10. Jules Dupuit, "De la mesure de l'utilité des travaux publics" *Annales des Ponts et Chaussees,* second series, VIII, 1844.

11. The term *missing money* was first used to describe fixed-cost recovery in power by Peter Cramton and Steven Stoft in their 2006 paper, "The Convergence of Market Designs for Adequate Generating Capacity," written for the California Independent System Operator's Electricity Oversight Board.

incremental costs associated with producing more and more output without expanding capacity—a marginal cost characteristic of technologies that reflect the law of diminishing marginal returns. Eventually, the incremental costs of expanding output without expanding capacity reach the level of average total costs. At this point, market-clearing prices are high enough to support deploying new capital to expand capacity, and there is a lower cost to expand output with new capacity than to expand output by employing just more variable inputs. This end state is the textbook case of corrective market forces that will move the market to a long-run competitive equilibrium.

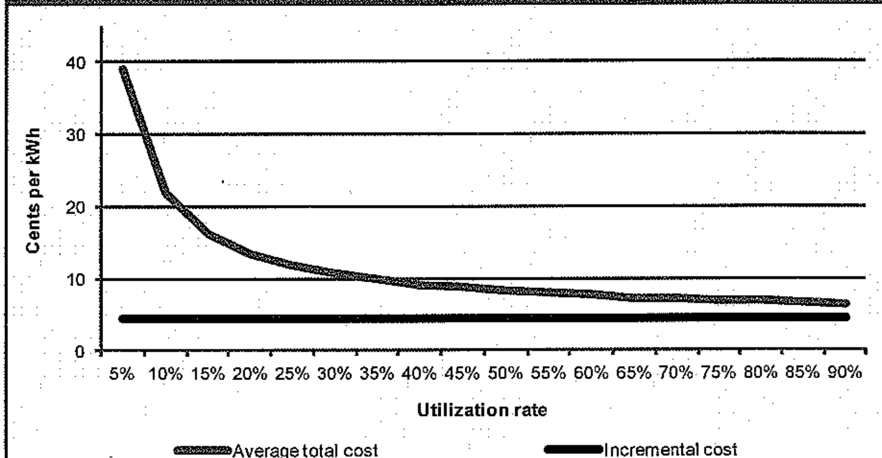
The inherent flaw in electric energy markets is that **power generation technologies can alter output with fixed capacity by adjusting variable inputs such as fuel; but the impact of the law of diminishing marginal returns is not strong enough to close the gap between incremental generating costs and average total costs before the capacity reaches its utilization limit.** But power plants do not run at their maximum utilization rate when demand and supply are in balance because customers do not need the same amount of power at all times. The average hourly demand for power is typically about 60% of the maximum hourly demand (the ratio of average load to peak load is the power system load factor). In a power system with a reserve margin adequate to ensure reliability, the average utilization rate of installed generating capacity is a little less than the system load factor.

As a result, when power demand and supply are in balance—including the desired reserve margin of productive capacity—the average utilization rate of a power plant approaches the system load factor, and the incremental cost–based market-clearing price remains significantly below average total costs.

Figure 2 illustrates the inherent problem with power generation technology cost profiles. A tightening demand and supply balance causes higher power plant utilization; but although the gap between incremental costs and average total costs narrows, it does not close as average utilization increases and approaches the system load factor. As a result, this characteristic of power supply technologies means a chronic shortfall between incremental cost–based market-clearing energy prices and average total costs—a predictable outcome in a competitive energy marketplace.

Figure 2

Average and incremental cost of natural gas–fired combined-cycle electricity generating technology



Note: kWh = kilowatt-hour(s).
Source: IHS Energy

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The inherent missing money problem for power generating technologies is magnified when market interventions impose additional supply into the marketplace and lower the market-clearing price. For example, imposing mandates for renewable power generation increases the supply of technologies with a zero marginal cost. Adding these resources to the electric energy market supply curve lowers the market-clearing electric energy price. This price suppression is magnified by the subsidies available for each unit of wind electric output. Under these conditions, rival renewable generators find that they can bid negative prices as long as the subsidies they earn are more than enough to cover the cost of paying buyers to take their power. As a result, when subsidized wind resources bid against each other to clear an energy marketplace, the price can be driven to a negative level.

Altering power deregulation plans

The economic impact of the California power crisis of 2000–01 was so severe that it altered power industry restructuring plans not only in California but around the world. California made structural adjustments after recognizing that prosecuting law-breaking power traders and trying to recover the ill-gotten gains of the power crisis did not address the root cause of the shortages. After using an ad hoc approach of power plant contracts following the crisis, California instituted a resource adequacy rule in 2004 that became binding in 2006. This new rule required all load-serving entities to have enough capacity to meet their customers' aggregate demand plus a minimum reserve margin. The rule created a demand for capacity and enabled an informal capacity market to arise. An informal marketplace does not organize market interactions but rather relies on capacity buyers and sellers to seek each other out for transactions. The resulting contract prices, terms, and conditions were typically known only to the contract counterparties, however, and thus the informal market provided little capacity price transparency.

Michigan's PSC began altering its deregulation plan by initiating its own study of the evolving power sector. PSC Chairman Peter Lark released the "Michigan's 21st Century Electric Energy Plan" in January 2007. The Michigan Legislature responded to the report's recommendations and altered the course of electricity industry restructuring with the passage of PAs 286 and 295 in 2008. This legislation made three major changes:

- **Freeze retail open access.** The plan to eventually have 100% of customers with retail open access was changed to limit it to just customers involved in iron ore mining and processing, along with 10% of the remaining average weather-normalized retail electric load.

- **Establish utility integrated resource planning.** The plan to rely on the marketplace for timely and adequate electric supply expansion was changed in favor of an integrated resource planning process in which utilities detailed their expected demand and proposed supply actions, including PSC approval of a Certificate of Need for new generating capacity, before commencing construction.

- **Mandate renewable power supply.** This market intervention overrode the market result and imposed a minimum percentage of power supply from renewable power sources.

Market institutions—ISOs and regional transmission organizations—evolved rules governing power marketplaces to address the reliability challenges caused by the missing money problem. However, the regional market structural adjustments were quite varied. Three structural adjustments to the power industry relevant to Michigan included

- **MISO resource adequacy requirement**

- **MISO formal capacity market**

- **PJM formal forward capacity market**

MISO followed other power systems in addressing the missing money problem by evolving beyond its initial plan for an energy-only market design. From the start, the MISO energy market consistently delivered an efficient utilization of available electric capacity in the short run by clearing the market with prices that reflect the incremental variable costs of generation. As a result, the level and volatility of MISO energy prices typically covered the fuel and variable operating and maintenance costs of generating plants and provided some contribution to fixed costs. Yet after operating with an energy-only market design for a decade, MISO altered its rules to include a resource adequacy mandate in 2009. The resource adequacy mandate created an informal capacity market in MISO.

Four years after mandating a resource adequacy rule, MISO enhanced the mandate by implementing a formal capacity market to clear demand and supply about two months in advance of the annual peak demand. With the enhanced resource adequacy approach, MISO runs a voluntary capacity auction each April to balance capacity demand and supply for the 12-month supply period beginning each June (2015 was its third auction). This formal market enables AESs to cover any capacity needs that have not been covered in the informal marketplace and yet are still needed to meet their resource adequacy mandate.[12] In addition, the formal MISO marketplace increased capacity price transparency.

Unlike California and MISO, PJM began power restructuring with both energy and capacity marketplaces. However, after five years of experience with its formal capacity market, known as the capacity credit market, PJM found that

12. "First Annual Capacity Auction Cleared Under New RA Construct," MISO Energy, 5 April 2013.

this market design produced a boom-and-bust capacity price pattern and concluded that the power supply investment price signal could be improved by reducing the market's volatility. PJM responded by evolving its formal capacity market into a formal *forward* capacity market that cleared projected capacity demand and supply three years in advance with a payment commitment term of one to three years. In addition, the volatility of the capacity price was further limited by instituting a managed capacity demand curve and applying more stringent bidding rules to establish the capacity supply curve.

Regulated utility rates include full power supply cost recovery

The shortcomings of power deregulation to produce power prices high enough to fully cover costs created a renewed appreciation for regulated utilities whose retail rates reflected the total costs of power supply. These regulated rates covered the costs of reliably providing consumers with the electricity that they need, when they need it. To do this requires covering the costs to build and operate an efficient, diverse, and environmentally compliant generation portfolio that includes peaking, cycling, and base-load power plants along with demand-side resources and renewable resources.

Managing the ups and downs of electric energy use through time with storage technologies is more expensive than having enough capacity installed to meet needs at any point in time. Thus, planning for reliable power supply at all times focuses on the stock (megawatts) of productive capacity rather than flow of electric energy (megawatt-hours). Reliability requires sufficient available capacity to meet instantaneous power demand. A simple-cycle combustion turbine technology typically provides the lowest-cost pure capacity to meet aggregate consumer power demands. Although these *peaking* technologies are not the most efficient technologies in transforming fuel into electric energy, they are nevertheless the lowest up-front cost option to have a megawatt of capacity in place to meet power demands.

Since power reliability simply involves having adequate capacity, peaking technologies set the cost benchmark. The benchmark average annual levelized cost of the peaking technology is known as the "cost of new entry" (CONE). The CONE is adjusted whenever expected energy market and ancillary services cash flows can offset some of the up-front costs. This adjusted cost benchmark, known as "net CONE," reflects the value of "pure capacity" or in other words, the cost of reliability.

Although a utility finds that the lowest cost of pure capacity involves building a peaking unit, the utility does not build a power supply portfolio made up entirely by peaking technologies. Instead, a utility invests in a broad range of generation technologies making up a power supply portfolio designed to perform well in the long run. Some of the power supply technologies in this mix have capacity costs in excess of the combustion turbine—for example a natural gas–fired combined-cycle power plant that is more efficient at transforming natural gas into electric energy. In this case, the investment makes economic sense because the expected value of the fuel savings is more than enough to pay for the higher up-front capacity costs. The implication is that some of the additional capacity costs in a power supply portfolio that are over and above those of a combustion turbine are a cost-effective investment in fuel efficiency.

Some additional power plant investment provides production cost risk management. The cost of generating electricity is inherently uncertain. Oil, natural gas, coal, and uranium prices are difficult to predict and are prone to multiyear price cycles, short-term price volatility, and deliverability constraints. Alternative power generation technologies also rely on fuels with uncertain future prices and, in addition, have different performance risks. For example, hydroelectric power plants are limited by drought, whereas combustion turbine risks include, for instance, natural gas pipeline constraints on fuel deliverability.

Since technology performance characteristics and fuel price movements are not highly correlated, a diverse portfolio of fuels and technologies provides the most cost-effective way to manage the cost risk of power production. As a result, the additional cost of capacity over and above the combustion turbine reflects investment both in fuel efficiency and in risk management of power supply costs. Risk management investments are essential to reduce overall power supply costs—more stable costs create more stable cash flows. More stable cash flows reduce the size and thus cost of working capital and also lower the risk premium in the cost of capital.

Finally, some investments in power plants produce a cleaner environment. Utilities must try to balance environmental costs and benefits. To do this, some investments internalize the cost of pollution control technologies. Some of the higher variable costs of operation associated with pollution control are reflected in the incremental costs that set wholesale power prices some of the time. However, most of the environmental control costs are capitalized costs, and they are not covered by the capacity market cash flows that only cover the net CONE.

Evolving market designs still produce power supply cost recovery shortfalls

Cash flows from MISO energy and capacity markets addressed some, but not all, of the missing money problem. As a result, market cash flows continue to fall short of covering the total costs associated with an economically efficient and environmentally compliant generation portfolio.

MISO's enhanced resource adequacy construct created its capacity market. Resource adequacy means having enough capacity to reliably meet aggregate consumer demands. From a reliability perspective, market cash flows need to cover only the up-front cost of producing the lowest-cost source of capacity. Therefore, a metric to evaluate the MISO capacity market is the relationship of the capacity price to the net CONE.

Currently, the MISO Zone 7 net CONE is $65.10 per kilowatt per year (kW-year), and the CONE is $90.10/kW-year.[13] The difference between the MISO CONE and net CONE shows that even for a peaking power plant with an expected low utilization rate, the contribution from energy market cash flows accounts for about one-third of annual carrying charges of the up-front investment costs.

An investment pro forma for cycling and base-load units needs a higher percentage of annual up-front carrying costs to be covered by energy market contributions compared with a peaking unit. Therefore, a well-functioning energy market is essential to providing the energy margins needed to cover the additional up-front costs of cycling or base-load power plants that produce electric energy (megawatt-hours through time) more efficiently, more cleanly, or with less risk than the peaking unit.

Capacity market cash flow supplements energy market cash flow. In MISO, the capacity market cash flow only partially addresses the inherent technology-based dimension of the missing money problem, and it does not address the imposed renewable policy dimension of the problem. Policy interventions into the MISO energy market depress energy market cash flows, which then fall short of covering the additional costs of building a power generation portfolio with a cost-effective mix of peaking, cycling, and base-load power plants. On the revenue side, mandates for renewable power and subsidies based on renewable output depress wholesale prices and reduce power plant utilization rates. On the cost side of the energy cash flow, the renewable power mandates cause cycling power plants to start up, ramp up and down, and shut down more frequently to back up and fill in for the intermittent pattern of renewable power generation. The combined effect is to depress energy market revenues and increase variable operating costs for nonpeaking power plants. As a result, the market interventions impose missing money shortfalls in market cash flows and cause an underrecovery of the cycling and base-load costs in an efficient generation supply portfolio.

An uneven playing field for retail open access competition

Retail open access sets up competition on an uneven playing field between regulated and unregulated power suppliers. Unregulated suppliers can source energy and capacity from the marketplace at prices that are chronically below the average total power supply cost owing to the unresolved dimensions of the missing money problem. In contrast, regulated utilities' prices reflect average total power system costs.

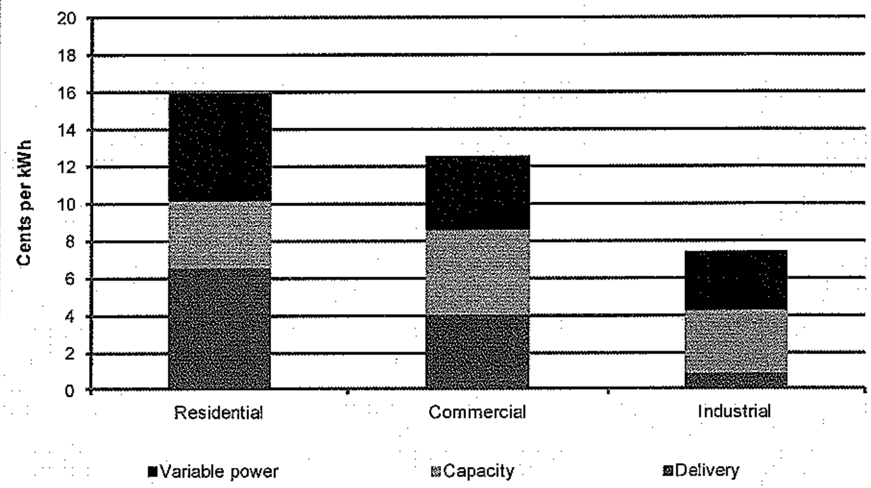
CMS and DTE are regulated utilities that serve more than 80% of Michigan's electric consumption. Regulated rates cover the average cost of all of the components needed to deliver cost-effective power supply. Figure 3 provides a breakdown of the components of the current regulated power rates for consumers by customer class in Michigan. In particular, the generation cost component of regulated retail power rates can be separated into variable production costs and the remaining capacity costs.

13. Gross CONE is cited in the MISO Locational Resource Zone Cost of New Entry filing to the Federal Energy Regulatory Commission (FERC), 3 September 2013. The $25.00/kW-year net revenue for a combustion turbine due to sales of energy and ancillary services is approximated from Figure 6 of the *2013 State of the Market Report for the MISO Electricity Markets*, Potomac Economics, June 2014.

Michigan regulated retail rates incorporate a variable cost component designed to cover average variable production costs. This component includes the cost of power purchased from the market as well as variable costs that are not included in the incremental costs that underpin market-clearing energy prices. For example, regulated variable charges usually cover power plant labor costs, whereas incremental cost for power production typically does not because power plant employment levels generally do not vary with short-run changes in power plant output. Therefore, a competitive bidder will bid to generate whenever the price is above incremental costs and thus make some contribution to fixed costs, including labor costs.

Figure 3

Michigan average retail rate components



Notes: Prices based on DTE schedules D1, D3, and D11 and CMS schedules RS, GSD, and GP
Source: IHS Energy, DTE, CMS, Michigan PSC

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In 2013, the average regulated energy price in Michigan was 4.49 cents/kWh compared with the MISO Zone 7 average wholesale price of electric energy of 3.38 cents/kWh.[14]

In the regulated price, the component covering the average cost of capacity ranges from 3 to 4 cents/kWh across different customer classes. This nonvariable generating cost reflects the average historical embedded cost of capacity in the utility generation portfolio. Using the ratio of peak demand to average demand allows conversion of this cents-per-kilowatt-hour charge to a dollar-per-kilowatt-per-year charge. The conversion yields a charge of about $200/kW-year representing the embedded cost of capacity in regulated rates.[15] Roughly one-third of the regulated embedded capacity charge covers the investments made to provide reliability (net CONE). The remaining two-thirds covers the cost to provide production efficiencies through a mix of peaking, cycling, and base-load resources; risk mitigation through a diverse fuel and operating technology mix; and compliance with existing environmental regulations through environmental control investments.

The market-clearing MISO Zone 7 capacity price for the summer of 2015 was $1.27/kW-year. This price is lower than the $6.10/kW-year market-clearing MISO Zone 7 capacity price for the summer of 2014. To put these prices into perspective, the capacity price needs to be around $65.10/kW-year to provide the cash flow necessary to cover the net CONE. Therefore, experience to date shows MISO Zone 7 capacity prices are less than 10% of the net CONE benchmark and indicate that market prices are currently in the bust phase of a capacity price cycle.

Figure 4 compares the cost coverage of the current capacity costs embedded in Michigan regulated rates to the cost coverage of the recent market-clearing MISO capacity price. Since MISO capacity prices were in the bust phase in 2014, this price level enabled retail open access customers to pay an estimated $290 million less for the various benefits of Michigan's installed capacity portfolio compared with utility ratepayers.

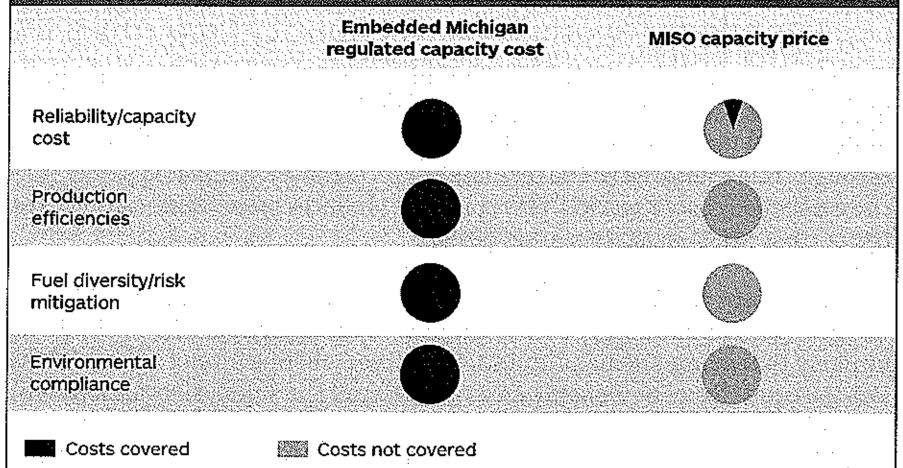
The MISO capacity and energy market designs produce market-based cash flows that do not fully cover power supply costs, whereas regulated rates cover the total costs of power supply. Yet the same power system produces electric supply for retail open access customers as well as utility ratepayers; the level of reliability, sources of energy, and environmental impact of the power supply are the same for all consumers. Despite this common source, customers choosing suppliers that source capacity and energy from the market pay less than utility ratepayers that cover the entire cost of producing

14. Regulated cost of energy based on weighted-average cost of energy from rate cases DTE (U-17767) and CMS (U-17735); MISO Zone 7 price is the Michigan Hub average day-ahead wholesale price.

15. Based on weighted-average load factors and costs of capacity from DTE rate schedules.

electricity with a cost-effective, environmentally compliant generation portfolio. The uneven playing field for AESs and utilities creates an unfair cost distribution between consumers served by AESs sourcing power system outputs at market prices and regulated utilities providing power on an average cost basis.

Figure 4



Cost coverage of current capacity costs: Michigan regulated rates versus recent market-clearing MISO capacity price

Source: IHS Energy

© 2015 IHS: 50505-1

Systemwide benefit for free riders

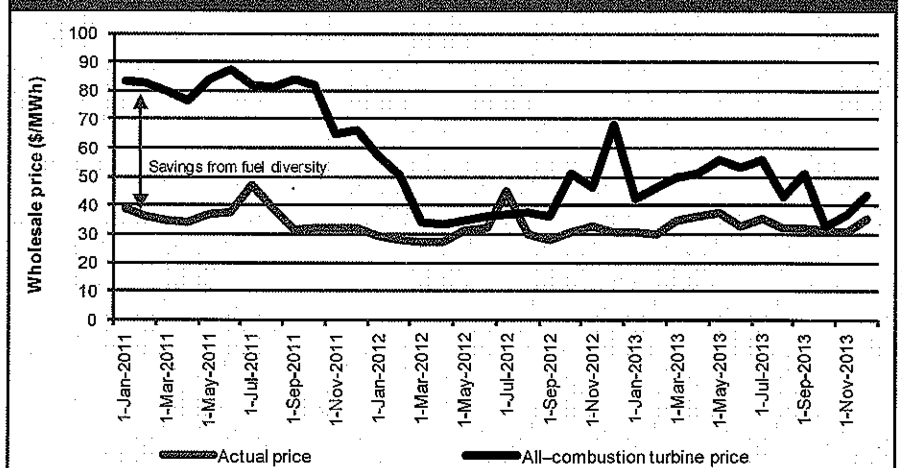
Michigan's free rider problem accounts for an annual average cost shift of nearly $300 million to utility ratepayers and away from retail open access customers being served by AESs sourcing market-based capacity and energy. On average, two-thirds of the cost shift involves the fixed costs of power supply, and one-third involves variable costs.

Michigan utility ratepayers create overall system benefits by funding investments in production efficiency, risk management, and environmental impact mitigation. These benefits spill over to the marketplace and produce cleaner, more cost-effective, and less volatile market-clearing power prices because regulated utility-owned power plants compete in the MISO wholesale energy market. Retail open access customers are free riders because these systemwide benefits are inherent in delivering power.

The benefit of cost risk management is significant. For example, the diverse Michigan power supply portfolio produces incremental generating costs that are lower and less volatile than an all natural gas–fired generation portfolio. Figure 5 shows that if Michigan power supply lacked fuel and technology diversity and relied on only natural gas–fired combustion turbines for power supply, then the wholesale price of power in the state of Michigan from 2010 to 2013 would have been over 50% higher, and the monthly price variation would have been over three times greater than the actual level and variations in market-clearing prices. Here again, consumers paying market-based power prices for energy are free riders that benefit from, but do not pay for, the investments made to diversify the fuel and technology mix.

Demand-side management programs also produce systemwide benefits. The impact of the accumulated investment

Figure 5



Michigan monthly prices versus modeled all–combustion turbine price, 2011–13

Notes: All–combustion turbine price modeled with the IHS Power System Razor model.
Source: IHS Energy, Ventyx Velocity Suite

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in these programs reduces aggregate consumer demand for capacity and thus reduces and delays increases in the market-clearing price of capacity.

Market prices for energy and capacity vary more than regulated prices

Market prices and regulated costs differ in variability as well as levels. Both characteristics create an uneven playing field for retail open access. The combination of the boom-and-bust market capacity prices pattern plus the wholesale energy price pattern makes the market costs of power (the sum of market capacity and energy prices) significantly more variable through time compared to the regulated costs of power. Regulated power prices incorporate capacity costs that reflect the embedded cost of service. This approach produces more stable capacity costs than the expected capacity prices under the current MISO capacity market design.

Boom-and-bust capacity price patterns are a predictable result of the MISO formal capacity market design incorporating *inelastic* demand and supply curves. Demand and supply conditions vary enough from one year to the next that it is unlikely that market demand and supply curves will line up and allow MISO Zone 7 prices to consistently clear at the average total cost of new supply. Instead, demand and supply fluctuations will produce a boom-and-bust price pattern.

The MISO capacity demand and supply curves are price inelastic. In the short run, MISO power demand will not change much in just a few months in response to a change in the capacity price. This short lead time does not allow enough time for demand to respond to price signals, so demand is price inelastic. Similarly, the supply curve is also price inelastic because the formal capacity market clears less than two months ahead of the supply period, and such a short lead time does not allow enough time for new supply build to enter the market in response to these price signals and change the demand and supply balance.

A market with price-inelastic demand and supply curves tends to produce volatile prices around average total costs when demand and supply are close to balance. The Appendix describes why normal variations in demand and supply fundamentals will generate boom-and-bust pricing patterns when the market demand and supply curves are both price inelastic.

With only three years of MISO market-clearing prices, it is not clear where the average price will settle, on average, over the long run. However, if the MISO formal capacity market price were going to cover the average total cost of new capacity over the life of the power plant, then the boom prices have to be high enough over a long enough period of time to make up for the intervals of bust price levels. Looking ahead, the expected increase in demand and decline in supply are likely to produce boom prices around 2020. If recent prices are an indicator of bust price levels, then bust prices will typically be around 10% of net CONE. In contrast, boom prices are limited by the MISO capacity price cap. With these price levels, boom prices would need to prevail roughly 70% of the time to offset the impact of bust prices during the other 30% of the time. However, since the MISO capacity market outcomes are simply too few to provide a useful sample to assess the expected long-run average price result, and the observations of similar capacity market designs were also too limited, it is not possible to conclude that this capacity market design will produce a price that averaged to net CONE over the life of a generating asset.

The expectation that the MISO capacity market design will produce boom-and-bust prices is not just theoretical. Other power markets provide price experience with similar capacity market designs. In particular, PJM employed a formal capacity market design from 2000 to 2004 that is similar to MISO's. As Figure 6 shows, this capacity market design produced boom-and-bust patterns for capacity prices that did not average to net CONE over an extended period of time.

An additional source of volatility in the cost of electricity sourced from the marketplace comes from the varying price of energy, as measured by prices in the wholesale market. MISO's price of energy varies more than the regulated variable charge of energy. Figure 7 shows market prices that reflect the incremental fuel costs of rival fuel generators. Natural gas–fired power plants are often the marginal generators with bids that set the market-clearing price. In MISO North (MISO excluding Entergy), natural gas–fired power plants constitute 27% of installed capacity and are on the margin, setting prices about 29% of the time. As Figure 7 shows, natural gas prices are the most cyclical and volatile of the fuel sources used to generate electricity.

The natural gas price variation is a primary driver of the wholesale energy price variation. Figure 8 shows the monthly MISO Michigan Hub wholesale energy price variation. These market energy prices were three times more varied than the regulated Michigan monthly average variable cost of power production.[16]

Slight changes in the factors that influence consumer demand and installed capacity levels drive the boom-and-bust price patterns in the MISO capacity market. A different set of factors drives the ups and downs of natural gas prices and thus the wholesale price of energy. Although atypical, the potential exists for a coincident run-up of market prices for both energy and capacity. These various situations create a valuable option for customers that can always switch to buy the lower of regulated or market-based power supply prices for energy and capacity. For example, for several years during the previous decade, market wholesale power rates exceeded regulated rates, and retail open access participation dropped nearly to zero.

Figure 6

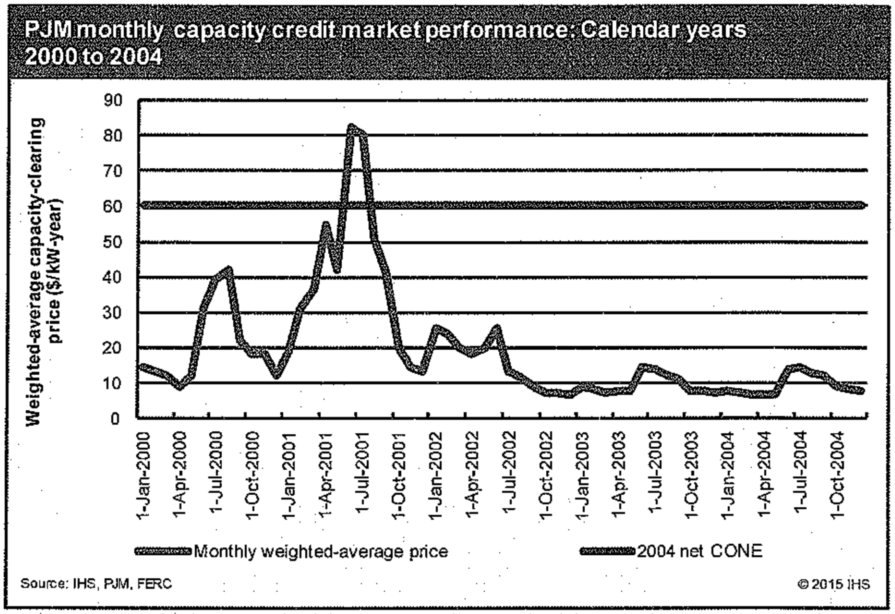
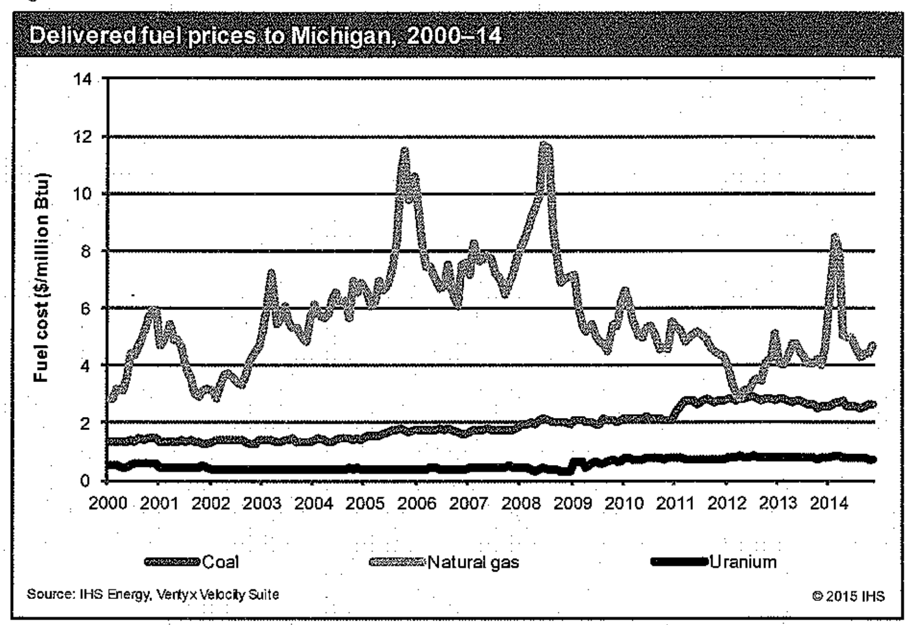


Figure 7



A discriminatory retail open access option—confirmed by consumer actions

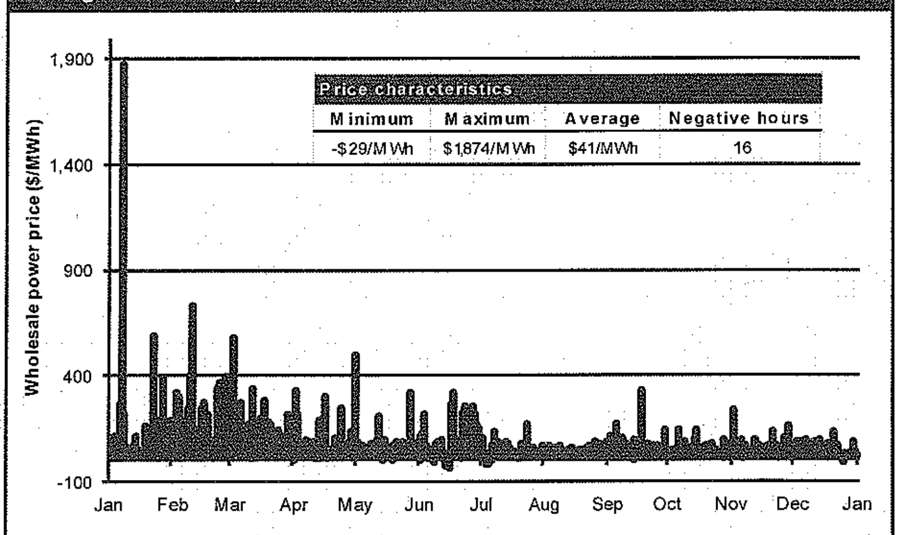
The unintended consequence of the retail open access level of 10% of power demand is the creation of a valuable option for some customers but not others. Consumers with that option can switch to avoid paying their share of capacity costs by timing their switching activity between AESs and regulated utilities. Retail open access consumers will select an AES that sources supply from the capacity marketplace when the provider is passing through a capacity price well below the regulated price (bust periods). When the AES price incorporates boom market capacity prices that are well above the regulated capacity price, these customers will switch back to the regulated utility. Well-timed switching allows these customers to avoid paying their share of the full costs of power capacity, in particular because of the relatively short notice required to switch suppliers, making it easier to time switching to benefit from pricing differences.

16. Comparison based on the statistical measure of the "coefficient of variation" defined as the standard deviation divided by the mean.

The value of the free ride and discriminatory option provided by limited retail open access has not gone unnoticed. Not surprisingly, the waiting list for the retail open access program is twice as large as the current participation limits.[17] As of January 2015, close to 11,000 utility customers were in the queue to acquire these advantages through the existing retail open access program.

Figure 8

Michigan hub hourly prices, 2014



Source: IHS Energy, Vertyx Velocity Suite © 2015 IHS

Looking ahead, the program providing this valuable free option will likely remain oversubscribed. There is some potential for dramatic swings when market capacity prices boom and natural gas prices spike, driving customers to opt out. Yet they will likely quickly return when the capacity market cycles back to a bust pricing phase and customers swing away from regulated supply. Note that most of the current retail open access customers are nonresidential consumers with more than 1 MW of demand, so the current misalignment disproportionately shifts the cost burden onto, and discriminates against, residential consumers.

Short-run switching options hinder balancing demand and supply in the long run

Retail open access customers' ability to switch suppliers in the short run creates uncertainty over power supply responsibilities and long-run planning. Competitive forces drive AESs to satisfy some of their needs from the short-run capacity market. When uncertain market conditions shift from bust to boom, regulated power costs improve relative to market-sourced power supply. In addition, the energy market price can also run up owing to cyclical fluctuations of the delivered price of marginal generation fuels—especially natural gas. A combination of booming capacity prices and high incremental generating fuel prices creates conditions that force market-sourcing power suppliers to try to pass these costs on to customers; but these customers will then have a strong economic incentive to switch back to a regulated power provider and pay the temporarily lower electricity rates reflecting the average embedded historical capacity cost and average variable costs. The problem is that the timing of such relative price reversals is hard to predict, and market conditions can turn quickly. Therefore regulated suppliers are unlikely to have the certainty or lead time to respond. The probability that utilities will be put in this position is increasing as MISO capacity prices are poised to move out of the bust phase around 2020.

Utilities ensure reliability by projecting power demand and supply years in advance. Supply development involves multiyear lead times to plan, site, permit, and construct new resources that, once built, typically operate for decades. Consequently, prudent planning requires reliability assessments covering many years ahead. The objective of power supply planning is to ensure enough installed electric generating capacity in place to meet expected aggregate consumer demands plus a reserve margin to protect against the impact of adverse conditions, such as extreme weather, greater-than-normal power plant outages, low output from intermittent resources (e.g., wind power), and demand forecast error.

In Michigan, the target planning reserve margin is 14.8%, reflecting the reliability standards set by ReliabilityFirst, the organization responsible for the regional electric reliability planning that includes Michigan. ReliabilityFirst is part of the North American Electric Reliability Corporation, which implements federal mandates for electric reliability under

17. According to the 2014 "Status of Electric Competition in Michigan" report released by the Michigan PSC, there are 6,460 customers enrolled in retail open access and approximately 11,000 in the queue.

the regulatory oversight of FERC. ReliabilityFirst is also responsible for imposing penalties for violations of its reliability standards.

Demand and supply trends brought Michigan's power system into long-run balance close to a decade ago. In 2006, the Michigan PSC projected an electric demand and supply balance in the near future but an insufficient pipeline of new supply under development for subsequent years. The *Michigan Capacity Needs Forum: Staff Report to Michigan Public Service Commission* concluded in January 2006

> *Unless there are some significant enhancements to existing supplies, growing demand will cause existing electric generation and transmission capacity to be insufficient to maintain reliability standards in the Lower Peninsula.*

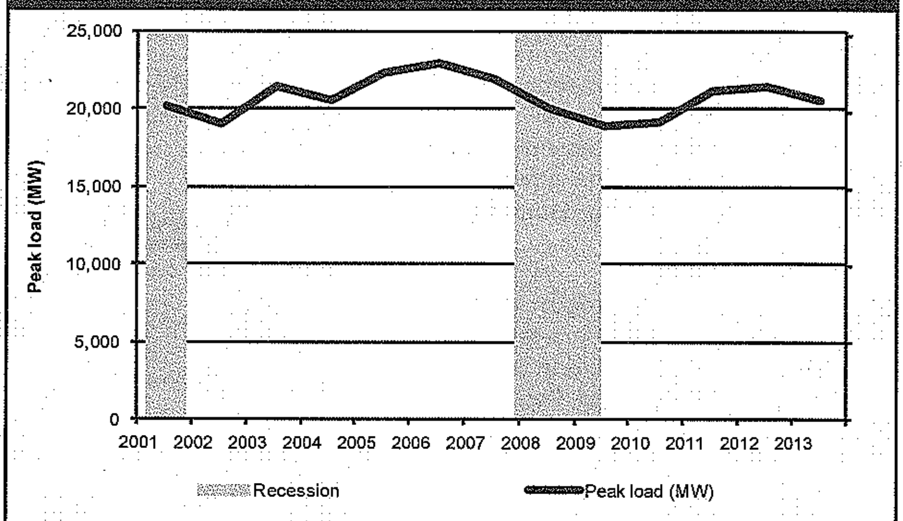
Shortly after the PSC reliability assessment, the business cycle produced an unanticipated temporary reprieve from the impending power supply shortfall in the Lower Peninsula. At the end of 2007, the most severe economic downturn since the Great Depression began. Reduced business activity and lower household purchasing power reduced power demand. The economic downturn dropped Michigan peak power demand by over 3,000 MW (December 2007 to June 2009). Michigan economic data indicate that the economic downturn hit the state sooner and the economic upswing took hold later than the overall US economic cycle. Nevertheless, as the US economic recovery gained traction, so too have the Michigan economy and electric power demand recovered.

The temporary impact of the business cycle on long-run electricity consumption trends is nothing new. The previous US economic recession (March to November 2001) reduced power demand, and then the subsequent economic expansion increased power demand faster than the underlying trend from 2002 to 2007. As the economy pushed electric demand upward, variations from normal weather conditions moved annual power demand up or down by as much as 1,000 MW. Figure 9 shows the combination of atypical weather impacts and business cyclical impacts on Michigan Zone 7 power demand through time.

A prudent plan to balance power demand and supply in the long run does not try to pace supply development with the short-run influences of the business cycle. Predicting the timing of business cycles is so uncertain that it is prudent to plan to have enough electric generating capacity to meet power demands when the economy is operating at full employment, even though an economic downturn can depress power demand for several years compared with the expected power use with normal economic activity. In 2006, prudent electric supply planning could not delay the development of new resources by betting on lower power demand because of an upcoming multiyear economic downturn.

Figure 9

Michigan Zone 7 electricity demand, 2001–13



Source: IHS Energy, Ventyx Velocity Suite, US Energy Information Administration, National Bureau of Economic Research © 2015 IHS

Looking ahead, the economic recovery that began in mid-2009 continues to push Michigan electric use higher. But on the supply side, current Michigan Zone 7 trends are moving in a negative direction. In particular, the pace of power plant retirements is accelerating and outpacing capacity additions owing to a confluence of factors including conventional air pollution regulations and structurally lower natural gas prices. Additional power plant retirements are expected given the uncertainty around the proposed US Environmental Protection Agency regulations to reduce greenhouse gas emissions from existing power plants. In addition, the wholesale electric energy and capacity prices are still below the level needed to support power supply development by nonregulated suppliers and are not triggering enough overall new power plant development. Instead, wholesale capacity and energy prices are triggering additional power plant retirements.

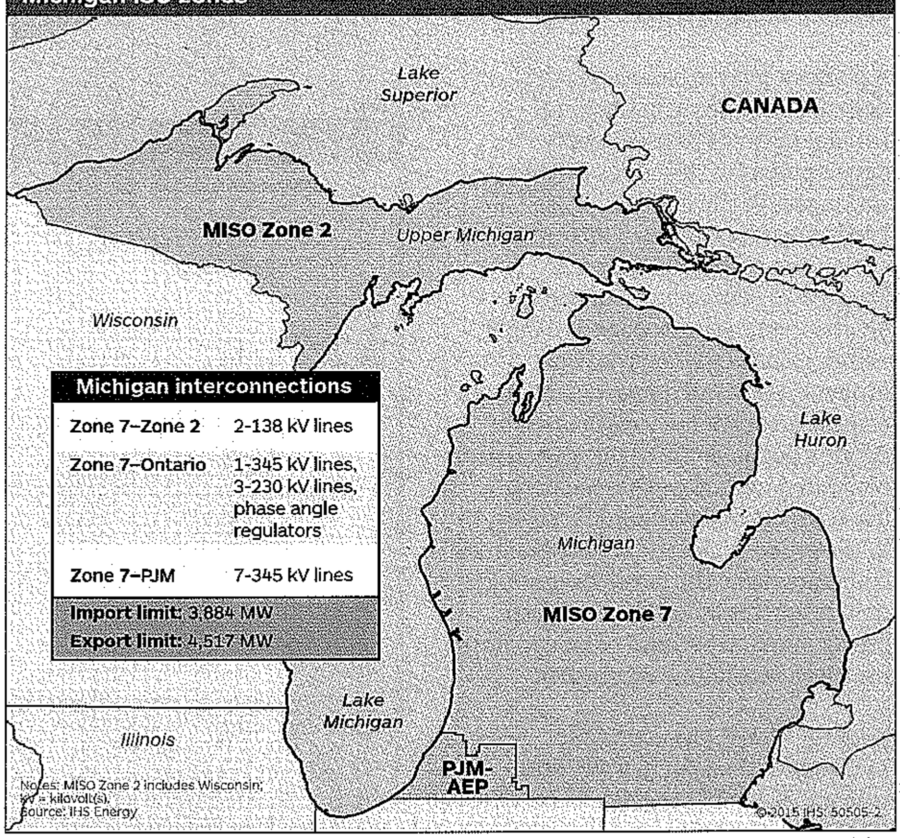
Tightening environmental regulations are accelerating the rate of power plant retirements. Current trends indicate that MISO Zone 7 will have a net loss of 612 MW of electric generating capacity by 2016. Scheduled retirements of coal-fired electric generating capacity equal 1,200 MW (1,000 MW owned by CMS and 200 MW owned by DTE).[18] Expected electric generating capacity additions by 2016 in MISO Zone 7 are 860 MW, including 540 MW of natural gas–fired generating capacity and 320 MW of wind capacity. The MISO electric reliability assessments discount wind capacity additions by 85% owing to the intermittent generation pattern driven by variable wind conditions.

Current electric energy and capacity prices are not high enough to cover the average total cost of new power supply. As a result, the current pipeline of new supply development is not adequate to keep overall demand and supply in balance in the years ahead. Power supply underinvestment is increasing the probability of a power supply shortfall in Michigan's Lower Peninsula around 2020. The most recent regional electric reliability survey projects that power supply will fall 1,200–1,300 MW short of the expected MISO Zone 7 capacity requirement in 2016. To put this shortfall in context, the expected Michigan Lower Peninsula (MISO Zone 7) capacity requirement for 2016 is 24.3 GW. For the next few years, however, the capacity surplus in other MISO zones can make up for this Zone 7 capacity deficiency, but the survey also notes that these conditions will last only through 2019. The survey concludes that additional power supply resources are required to ensure sufficient reliability beyond 2019. The implication is that planning and construction of these additional resources needs to begin now in order to have the needed power supply in place five years from now.[19]

The concern over power reliability in the Michigan Lower Peninsula, rather than in the entire state, arises because the adequacy of installed capacity is not defined by political boundaries. Instead, power reliability assessment is defined by the power grid—the wires that physically interconnect homes and businesses with power plants. Power grid operation is complex; and consequently, the degree of transmission network interconnection defines the separate regional power zones for balancing electric demand and supply (see Figure 10).

Figure 10

Michigan ISO zones



Michigan interconnections	
Zone 7–Zone 2	2-138 kV lines
Zone 7–Ontario	1-345 kV lines, 3-230 kV lines, phase angle regulators
Zone 7–PJM	7-345 kV lines
Import limit: 3,884 MW	
Export limit: 4,517 MW	

Notes: MISO Zone 2 includes Wisconsin; kV = kilovolt(s).
Source: IHS Energy

Michigan's power zones are part of two larger regional power systems. Most of the Michigan power sector is in MISO, and the remainder is in PJM. Both power systems rely on independent third parties to coordinate and orchestrate power system operations. MISO and PJM operate wholesale electric energy markets and use market-clearing prices to orchestrate the efficient utilization of existing power supply resources, within the existing transmission constraints, to generate

18. CMS retirements are detailed in MPSC Case 17473, opened 9 September 2013. DTE retirements are reported in "DTE Energy to close two units at Trenton Channel Power Plant in 2016," The *News-Herald*, 24 July 2014.

19. *2015 OMS MISO Survey Results*, July 2015.

and deliver enough electric energy to meet consumer needs at any point in time. In addition, both regional operators run capacity markets—although employing quite different approaches—to establish a capacity price intended to help keep demand and supply in balance over the long run.

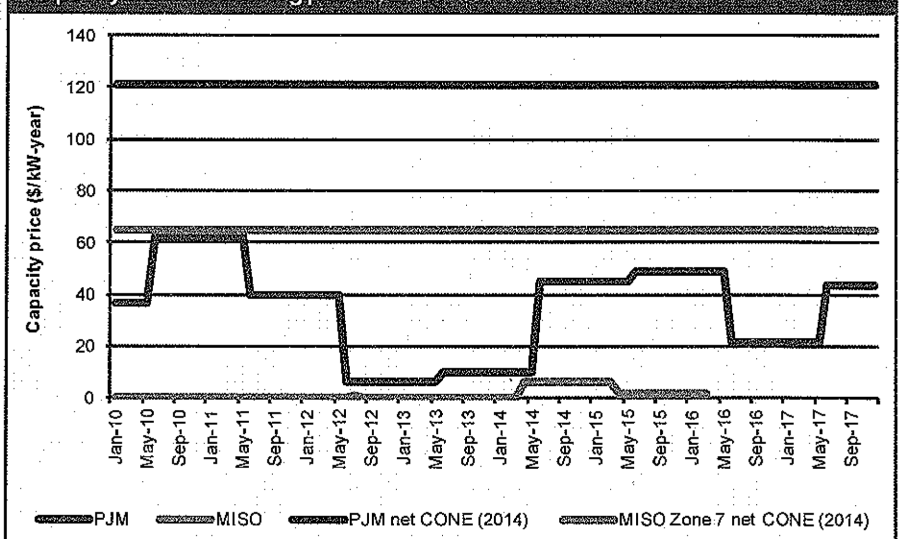
Pricing hubs in each zone are located at points where the transmission network enables rival generators to compete to deliver electric generation to meet aggregate consumer needs. MISO Zone 7 has its own pricing hubs for both electric energy and capacity commodities.

Michigan cannot rely on outside supply coming to the rescue when a power shortage develops. High-voltage transmission lines link MISO Zone 7 with power supply in PJM, Ontario, and MISO Zone 2. These linkages provide a combined capacity import capability of 3,884 MW. However, the projected MISO Zone 7 power supply shortfall already takes this transmission transfer capability into account in the reliability assessment, so there is no additional power supply from outside MISO Zone 7 that could relieve the power supply shortfall.

Indeed, transmission linkages have the potential to aggravate Michigan's reliability challenges. MISO and PJM capacity market designs are different. They produce different pricing patterns and create incentives for power plants to switch supply in the short run to whichever market provides greater compensation for capacity. Figure 11 shows that the PJM capacity market produces a higher payment than the MISO Zone 7 capacity market. As a result, power suppliers have an economic incentive to move their supply to the area of greatest return. For example, the Covert Generating Company announced a transmission project on 23 September 2014 that will enable this (approximately) 1,000 MW natural gas–fired power plant to sell its capacity into the PJM capacity marketplace instead of into MISO.

Figure 11

Capacity market-clearing prices, 2010–17



Source: IHS Energy, PJM, MISO

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Michigan's Upper Peninsula provides an example of how misalignments between regulation and the marketplace undermined the long-run process of balancing demand and supply as well as caused a redistribution of the power supply cost burden (see the box "Presque Isle highlights Michigan's retail open access dilemma").

The current opportunity to realign Michigan regulatory processes and market realities

All too often, it takes a crisis to force changes in the power industry structure. In the case of the California power crisis, the evidence that underinvestment was preventing power supply from keeping up with demand was apparent, but actions did not materialize until after a severe shortage unfolded. More recently, the problems of natural gas and power supply coordination simmered for years on a back burner until the winter 2013/14 polar vortex forced power systems to reevaluate how they defined and paid for firm power supply.

Michigan's misalignments in its hybrid power industry structure create problems—unfair cost burdens, the discriminatory switching option, and the increasing probability for power system demand and supply instability. The misalignments between regulation and the marketplace shift roughly $300 million each year of costs away from

Presque Isle highlights Michigan's retail open access dilemma

An ongoing situation in Michigan and Wisconsin highlights the consequences and complications that can arise as a result of a retail open access option.

In 2008, Michigan allowed an exemption in retail open access restrictions and excluded mining companies from the 10% cap for retail open access load. This gave mining companies an unconstrained ability to switch into competitive electric service and back. In 2013, Cliffs Natural Resources (CNR) exercised this right and notified its regulated service provider, We Energies of Wisconsin, that it was switching to competitive supplier Integrys Energy Services Inc. of Chicago. CNR represented 85% of We Energies Upper Peninsula load. With such a substantial decrease in demand, and the pending costs of retrofits to meet forthcoming clean air standards, We Energies decided to close the Presque Isle coal-fired power plant serving the area.

However, MISO (the regional grid operator) prohibited We Energies from closing the plant because doing so would threaten regional grid reliability. MISO offered the plant a System Support Resource (SSR) contract to keep it online. The $52 million annual cost of this SSR contract was divided among all transmission line customers, an area much broader than the Upper Peninsula. Consumer backlash arose in Wisconsin over the cost increase and allocation of 92% of the costs to customers outside the Upper Peninsula. Further, the Wisconsin Public Utilities Commission disputed the allocation of charges to FERC, which ruled in its favor in July 2014.

In January 2015, a tentative deal was reached whereby We Energies agreed to sell its utility business to Upper Peninsula Power Co. (UPPCO), including the Presque Isle power plant for $1 and the customers and operations of its 10 hydroelectric dams, but not the dam assets. Notably, the plan also required that the mining company, CNR, buy power from UPPCO until the Presque plant shuts down—an estimated five years. In February 2015, FERC gave MISO 60 days to propose a new method of allocating the SSR costs in a follow-up to its earlier finding that the cost allocation method was "unjust, unreasonable and unduly discriminatory or preferential."*

However, in March 2015, We Energies reversed course and decided against selling the Upper Peninsula plant to the new utility, and CNR agreed not to take advantage of the retail open access law. On 23 April 2015, the Michigan PSC approved We Energies' proposed acquisition of Integrys. We Energies will not receive an SSR contract for the Presque Isle power plant as long as the mines remain full-requirement electric customers of We Energies until the earlier of 31 December 2019 or the date that a new clean generation plant commences operation on the Upper Peninsula of Michigan. FERC and the Wisconsin PSC have approved the merger, but reviews are pending before the state PSCs in Illinois and Minnesota.**

*FERC Order, "150 FERC 61,104," 19 February 2015, https://www.ferc.gov/whats-new/comm-meet/2015/021915/E-3.pdf, accessed 23 February 2015.

**Michigan PSC Case No. U-17682, 23 April 2015.

a minority of Michigan consumers (retail open access customers account for a little over 10% of the state's power consumption and approximately 0.5% of customers) to the majority of customers, the utility ratepayers. Doing nothing continues the unfair distribution of power supply costs and increases the probability of a serious power shortage in the Lower Peninsula around 2020.

Rather than wait for misalignments to create a crisis, Michigan has the opportunity to address its power sector challenges by realigning regulation to market realities in a way that ensures consumers get reliable, affordable, and sustainable electricity supply in the long run with a fair distribution of the associated cost burden.

The time has come for Michigan to realign its regulation with the regional power marketplace. Michigan has two primary options: phase out partial retail open access or adjust the partial retail open access program.

Phasing out partial retail open access

The first option is the most straightforward approach and simply involves a phaseout of partial retail open access by mandating a shift back to regulated utility supply. A planned phaseout allows utilities to incorporate all load into their integrated planning process. For example, this is the course of action taken in the state of Virginia in the wake of the California power crisis.

A plan to phase out retail open access would not have to displace existing AESs; they would have to source power supply from utilities at a nondiscriminatory cost. Such an arrangement has been in place for decades to allow municipally owned and rural electric cooperatives to operate alongside regulated utilities. This arrangement would allow continued competition among AESs in other areas, such as demand-side capabilities or distributed generation options.

Altering partial retail open access

The second option would alter the partial retail open access program—a less definitive and more complex approach. A two-pronged plan would add a system benefit surcharge and also add a rule requiring AESs to demonstrate a firm forward supply arrangement for the projected needs of their current customers to provide enough lead time (at least five to seven years) to develop not only peaking units but also the cycling and base-load power plants necessary for efficient and reliable power supply.

A systemwide benefits surcharge on the power purchased by retail open access customers can level the cost burden of utility investments that provide systemwide efficiency, risk management, and environmental benefits. Such a charge could eliminate the average annual free rider cost shift of roughly $300 million from retail open access customers onto utility ratepayers. However, this approach to the free rider problem does not solve the discriminatory option problem that gives retail open access customers an incentive to purchase capacity from the lower of regulated rates or market prices.

Both prongs of this approach to alter partial retail open access need to be part of the solution. Just altering the retail open access by adding a system benefit surcharge without also requiring a multiyear firm forward supply arrangement for projected consumer demand would worsen the discriminatory switching option and create greater instability in balancing power demand and supply and ensuring reliability in the long run.

Adding a systemwide benefits surcharge alone can equalize the average cost of power supply from AES and utilities; but it would not alter the difference in cost variations through time. The regulated power costs would continue to be relatively stable because it reflects the slowly changing average total costs. On the other hand, the cost of power from the AES would still vary more because of the boom-and-bust price pattern of market capacity prices and the variability of energy prices linked to the ups and downs of fossil fuel prices, especially natural gas. But reducing the difference between the average regulated and average AES power costs while differences remain in the cost variability around those averages will increase the frequency of customers exercising the option to switch back and forth. Thus the value of the retail open access option available to some but not all customers will increase. The average annual value of the retail open access switching option would rise from the current small value to around $41 million. Hence, mitigating this discriminatory customer option requires implementing both a systemwide benefits charge on AES consumers and a multiyear firm forward supply arrangement for projected consumer demand.

Conclusion

The implications of the current Michigan power sector challenges are clear—Michigan must realign its regulation with the market realities. Under the status quo, Michigan's hybrid power sector shifts roughly $300 million per year of costs away from a minority of Michigan consumers to the majority of customers, the utility ratepayers.

The need for corrective actions is urgent because the probability of unreliable power supply is increasing in Michigan. This misalignment between short-run customer switching and long-run supply planning is one reason why the current pipeline of new supply will not be able to keep up with system demand increases or replace retiring generating resources. The margin for error in balancing power demand and supply is small. In Michigan, a reserve margin of 14.8% is required to reliably balance power demand and supply. Dropping just 5 percentage points short of the target reserve margin substantially increases the probability of serious power system problems—emergency load shedding, brownouts, and price spikes altogether similar to what happened in California in 2000–01.

By addressing the misalignments in the current hybrid power industry that create an unfair cost burden, a discriminatory switching option, and the increasing probability for power system demand and supply instability, Michigan can ensure that its power system remains reliable, efficient, and environmentally compliant. Corrective actions will enable a fair and nondiscriminatory distribution of costs to customer classes and maintain the competitiveness of electric input costs to Michigan businesses operating in the global economy.

Appendix: MISO capacity market design produces a boom-and-bust price pattern

Boom-and-bust capacity price patterns are a predictable result of the MISO formal capacity market design incorporating *inelastic* demand and supply curves. Demand and supply conditions vary from one year to the next, and market demand and supply curves are unlikely to line up and allow MISO Zone 7 prices to consistently clear at the average total cost of new supply. Instead, demand and supply fluctuations around the market balance point will produce a boom-and-bust price pattern.

A well-functioning capacity market should consistently produce a market-clearing price close to the average total cost of supply when demand and supply are close to balance. However, a market with price-inelastic demand and supply curves tends to produce volatile prices around average total costs because of normal short-run variations in demand and supply conditions when demand and supply are close to long-run balance.

The price elasticity of demand measures the sensitivity of aggregate consumer power demand to price. If demand is relatively sensitive to price, then a price change will cause a more proportional change in demand, and so the demand is considered price *elastic*. For example, if a 10% increase in the price causes a greater than 10% decline in demand, then demand is price elastic. Conversely, if demand is relatively insensitive to price, then a price change will produce a less than proportional change in demand, and demand is considered price inelastic.

Graphically, the slope in a demand curve indicates the sensitivity to price. All else equal, a more horizontal demand curve indicates more sensitivity to price (price-elastic demand) and a steeper demand curve indicates less sensitivity of demand to price (price-inelastic demand). If demand is independent of price, then the demand curve is perfectly inelastic and vertical.

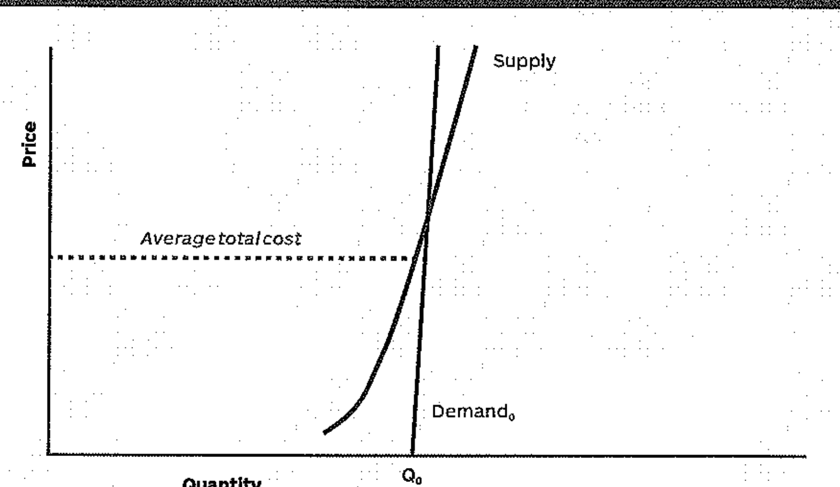
A concept similar to demand elasticity describes the sensitivity of supply to price. Capacity supply is more responsive to a forward price change (a price for supply set years into the future) compared to a price signal for supply just months ahead. Price elasticity is higher because a price signal years in advance provides enough time to respond with the design, siting, permitting, and construction of new supply. By contrast, typical power development lead times preclude altering supply much within a few months in response to a change in the capacity price. Graphically, an inelastic capacity supply curve has a steeper upward slope compared to a more elastic supply curve.

A well-functioning capacity market will balance demand and supply at a price sufficient to cover the average total cost of supply. Figure A-1 shows a market with the characteristics of the MISO capacity market—a vertical demand curve and an inelastic supply curve—intersecting to produce a market-clearing price equal to the average total cost of production.

Inelastic demand and supply curves are steeply sloping, and these shapes frame an unlikely and fragile market outcome in which price equals average total cost. The result is unlikely because all of the other factors that influence demand and supply need to position the intersection of these curves close to the average total cost. The result is fragile because even if demand and supply initially line up to produce a price equal to average total cost, any slight shift in demand or supply conditions will move the price significantly away from the average total cost. As a result, the normal

Figure A-1

Perfectly inelastic demand and relatively inelastic supply—In balance



Source: IHS Energy

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variations in demand and supply conditions will result in dramatic capacity price increases or decreases—the boom-and-bust price pattern.

Bust prices arise whenever slight shifts in demand or supply conditions throw the market out of long-run balance by increasing supply or reducing demand. For example, an economic downturn can reduce demand for a few years by several percent from expected long-run levels. A slight decline in demand shifts the demand curve to the left and causes the market-clearing price to fall dramatically—producing bust prices (see Figure A-2).

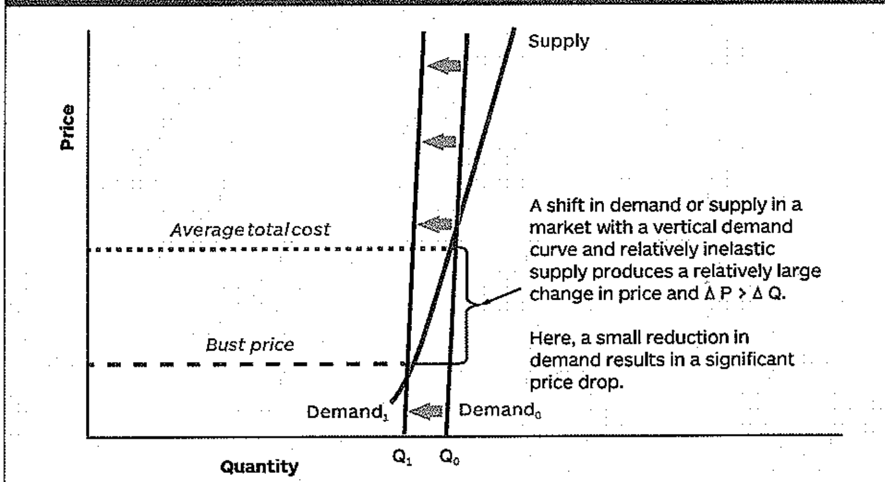
Boom prices arise whenever slight shifts in demand or supply conditions throw the market out of long-run balance by decreasing supply or increasing demand. For example, the multiyear lead time required to develop new power supply means that with a small error in forecasting demand that results in an underestimate, planned capacity will not meet actual demand. Figure A-3 illustrates how this error shifts the demand curve to the right of the expected level and causes prices to rise significantly above average total cost—producing boom prices.

When demand and supply are inelastic, then slight changes in power supply caused by the lumpy size of power plant additions and retirements trigger boom-and-bust price movements the same way as the slight changes in demand.

A boom-and-bust price pattern is not a typical market outcome when demand and supply curves are more price elastic. Greater-than-proportional changes in demand or supply in response to price changes mean that the shape of the demand and supply curves would be more horizontal. Figure A-4 shows that the same slight demand decline that produced bust prices with inelastic demand and supply curves will instead produce a small price change. As a result, the price level is still close to the average total cost when demand and supply curves are more elastic to price. Typically, this balance is not achieved in the electricity sector because the demand and supply curves are not usually elastic.

Figure A-2

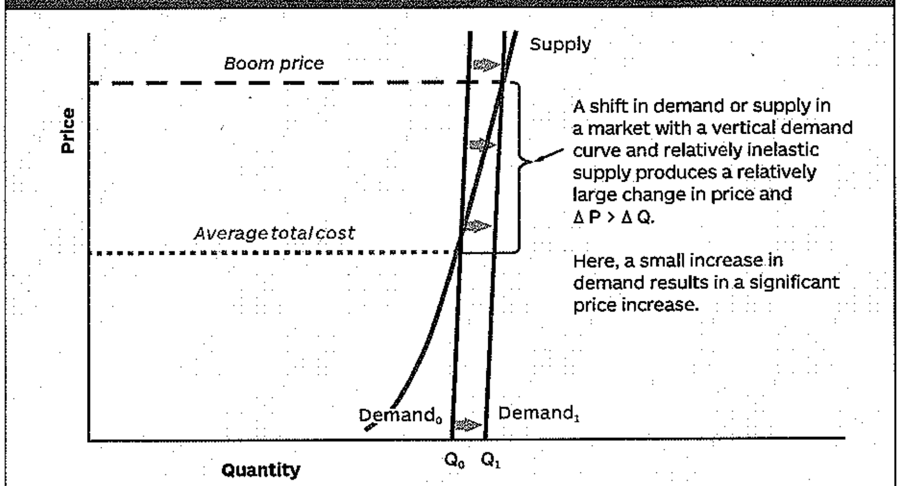
Perfectly inelastic demand and relatively inelastic supply—Price bust



Source: IHS Energy © 2015 IHS: 50505-4

Figure A-3

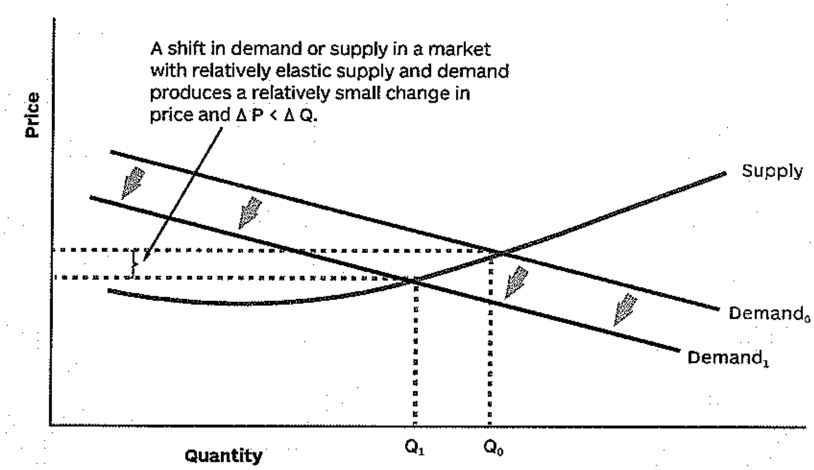
Perfectly inelastic demand and relatively inelastic supply—Price boom



Source: IHS Energy © 2015 IHS: 50505-5

Figure A-4

Elastic demand and supply illustrating demand shift



Source: IHS Energy